

RENEWABLE RESOURCES



Long-Term Renewable Resources Procurement Plan

**Draft Second Revised Plan
for Public Comment**

August 16, 2021

Prepared in accordance with the
Illinois Power Agency Act (20 ILCS 3855), and the Illinois Public Utilities Act (220 ILCS 5).

Table of Contents

1.	Introduction	1
1.1.	First Revised Plan Accomplishments.....	2
1.2.	Plan Organization	3
1.3.	Action Plan	4
2.	Legislative/Regulatory Requirements of the Plan	5
2.1.	Renewable Energy Resource Procurement Prior to Public Act 99-0906.....	5
2.1.1.	Original RPS—Eligible Retail Customer Load	5
2.1.2.	Original RPS—Hourly Pricing Customers	6
2.1.3.	Original RPS—ARES Compliance.....	7
2.2.	Public Act 99-0906	9
2.2.1.	Legislative Findings	10
2.2.2.	Changes to the RPS.....	11
2.2.3.	Concepts and Terms	11
2.2.4.	Long-Term Renewable Resources Procurement Plan	12
2.2.5.	Plan Requirements	13
2.2.6.	Items Not Included in Long-Term Renewable Resource Procurement Plan	19
2.2.7.	Revised Plan Development and Approval	20
2.2.8.	Plan Updates	21
2.3.	The RPS and Percentage-Based Goals of the RPS	22
2.3.1.	Load Applicable to RPS Goals.....	22
2.3.2.	Eligible Projects for the Illinois RPS.....	23
2.3.3.	Compliance Mechanism: RECs vs. “Renewable Energy Resources”	26
2.3.4.	RPS Funding and Rate Impact Cap	27
2.3.5.	Employment Opportunities	29
2.4.	Quantitative New Build Targets of the RPS	29
2.4.1.	Quantitative Procurement Requirements	30
2.4.2.	“New wind project” and “new photovoltaic project” Definition.....	31
2.4.3.	Initial Forward Procurements.....	32
2.4.4.	Subsequent Forward Procurements	32
2.4.5.	Balancing Expected Wind RECs vs. Solar RECs.....	33
2.5.	Adjustable Block & Community Renewable Generation Programs	34
2.5.1.	Adjustable Block Program	34
2.5.2.	Community Renewable Generation Program.....	38
2.6.	Illinois Solar for All Program.....	40
2.6.1.	Illinois Solar for All—Overview	41
2.6.2.	Illinois Solar for All—Sub-programs.....	44
2.6.3.	Illinois Solar for All—Additional Requirements	47
2.6.4.	Illinois Solar for All—Third-party Program Administrator	48
2.7.	2021 Legislative Proposals	49
2.8.	Legislative Audit Commission Report.....	49
3.	RPS Goals, Targets, and Budgets.....	51
3.1.	Statewide Goals and Allocation of Cost and RECs from RPS Procurements to Each Utility	52
3.2.	Impact of the Phase out of Alternative Retail Electric Supplier RPS Obligations	53
3.3.	Section 1-75(c)(1)(H)(i) ARES Option to Supply RECs for their Retail Customers	53
3.4.	MidAmerican Volumes.....	55
3.4.1.	Change to MidAmerican’s Load Forecast Methodology	56
3.4.2.	Correcting for the Unintended Consequences of MidAmerican’s Changed Forecast Approach	57

3.5.	Cost Cap and Cost Recovery	60
3.6.	RPS Compliance Procurement Priorities	61
3.7.	Wind/Solar Matching Requirement and Solar Split.....	61
3.8.	REC Portfolio.....	63
3.9.	Existing REC Portfolios - RECs Already Under Contract.....	63
3.10.	2019 and 2021 Forward Procurements	66
3.11.	Statewide REC Portfolio.....	66
3.12.	Loads, RPS Goals and Targets, and REC Gaps	67
3.13.	Applicable Retail Customer Load	67
3.14.	RPS Goals and Targets	67
3.15.	Overall REC Procurement Targets - REC Gap	68
3.16.	Procurement Targets to Meet Specific Wind-Solar Requirement and Overall RPS Targets.....	69
3.17.	RPS Budget.....	70
3.17.1.	Utilities Budgets	71
3.18.	Summary of REC Procurement Targets and RPS Budgets	76
3.19.	Alternative Compliance Payment Funds Held by the Utilities	76
3.20.	Budget Uncertainty Due to Unknowns in Project Energization Timelines	78
3.21.	Budget Uncertainty Due to Annual Load Variations	80
3.22.	Impact of RPS Budget on Procurement and Program Activities.....	81
3.23.	Spring 2021 RPS Budget Update and Proposed Payment Deferral Regime	83
3.23.1.	Introduction	83
3.23.2.	December 28, 2020 budget release	86
3.23.3.	March 3, 2021 Budget Update	87
3.23.4.	Precedent for Payment Deferrals: the 2010 LTPPAs.....	89
3.23.5.	Current RPS expenditure categories	90
3.23.6.	Key considerations in implementing a deferral regime	92
3.23.7.	2021-22 Delivery Year Payment Deferral Approach.....	95
3.23.8.	REC Delivery Contract Amendment.....	97
3.24.	Fall 2021 RPS Budget Update and Proposed Payment Deferral Regime for the 2022-2023 and 2023-2024 Delivery Years.....	97
3.24.1.	Introduction	97
3.24.2.	June 2021 RPS Budget Update.....	98
3.24.3.	Payment Deferral for 2022-2023 and 2023-2024 Delivery Years	101
4.	Renewable Energy Credit Eligibility.....	103
4.1.	Adjacent State Requirement	103
4.1.1.	Public Interest Criteria	105
4.1.2.	Application Process.....	111
4.2.	Cost Recovery Requirement	112
5.	Competitive Procurement Schedule	115
5.1.	Statutory Requirements.....	116
5.2.	Background on past REC Procurements conducted by the IPA	117
5.3.	The Agency's Competitive Procurement Approach.....	119
5.3.1.	Contracts.....	121
5.4.	REC Eligibility.....	121
5.5.	Credit Requirements.....	122
5.6.	Benchmarks.....	123
5.7.	Procurements for RECs from New Projects vs. RECs to Meet Annual Goals	123
5.8.	Procurements Conducted Under the Initial Plan and the First Revised Plan	125
5.9.	Competitive Procurements	127
5.9.1.	Forward Procurements.....	128

5.9.2.	Additional Competitive Procurements to Meet 2025 Target.....	128
5.9.3.	Brownfield Site Photovoltaic.....	129
5.9.4.	Other Renewables Forward Procurement.....	130
5.9.5.	Community Renewable Generation Program.....	130
5.9.6.	Proposed Competitive Procurements.....	131
5.10.	Wind/Solar Matching Requirement.....	131
5.11.	Procurements after 2023.....	132
6.	Adjustable Block Program.....	133
6.1.	Background.....	133
6.2.	Lessons From Other Jurisdictions.....	134
6.2.1.	Managing Initial Demand.....	135
6.3.	Block Structure.....	135
6.3.1.	Block Sizes.....	137
6.3.2.	Transition between Blocks.....	138
6.3.3.	Managing Waitlists.....	139
6.3.3.1.	Community Solar.....	139
6.3.3.1.1.	Waitlist for Replacing Lottery-Selected Projects.....	140
6.3.3.1.2.	Approach to Opening New Community Solar Blocks.....	140
6.3.3.2.	Distributed Generation.....	142
6.3.3.3.	Assignment or Sale of Waitlisted Projects.....	143
6.4.	REC Pricing Model.....	143
6.5.	Adjustments and Adders.....	148
6.5.1.	Size Category Adjustments.....	149
6.5.2.	Co-location of Distributed Generation Systems.....	149
6.5.3.	Community Solar.....	150
6.5.4.	Adders to Adjust for Changing System Revenue.....	152
6.6.	Payment Terms.....	153
6.7.	Contracts.....	154
6.8.	Adjustments to Blocks and Prices.....	156
6.8.1.	Net Metering Cap Adjustment.....	158
6.8.2.	Smart Inverter Rebate.....	158
6.8.3.	Federal Solar Investment Tax Credit Adjustment.....	159
6.8.4.	Tariffs on Foreign Photovoltaic Modules and Cells.....	159
6.9.	Approved Vendors.....	160
6.9.1.	Approved Vendor Designees.....	163
6.10.	Program Administrator.....	164
6.11.	Program Status.....	166
6.12.	Project Requirements.....	168
6.12.1.	Technical System Requirements.....	168
6.12.2.	Metering Requirements.....	169
6.13.	Customer Information Requirements/Consumer Protections.....	171
6.13.1.	Systems Energized Prior to Finalization of Consumer Protection Requirements.....	174
6.13.2.	Community Solar.....	175
6.13.3.	Monitoring of Consumer Complaints.....	176
6.13.4.	Disciplinary Determinations.....	176
6.14.	Application Process.....	178
6.14.1.	Batches.....	178
6.14.2.	Systems below 25 kW.....	179
6.14.3.	Application Fee.....	179
6.14.4.	Project Review.....	180

6.14.5.	Converting System Size into REC Quantities	180
6.14.6.	Batch Contract Approval	180
6.15.	Project Development Timeline and Extensions.....	182
6.15.1.	Development Time Allowed	182
6.15.2.	Extensions.....	183
6.15.3.	Project Completion and Energization.....	184
6.15.4.	Additional Requirements for Community Solar Projects	185
6.15.5.	REC Delivery	186
6.16.	Ongoing Performance Requirements.....	186
6.16.1.	Credit Requirements	187
6.16.2.	Options to Reduce REC Delivery Obligations	188
6.17.	Annual Report.....	189
7.	Community Renewable Generation Projects	191
7.1.	Statutory Overview.....	191
7.2.	Eligible Generating Technologies and Procurement/Program Eligibility.....	194
7.3.	Co-location of Projects.....	194
7.3.1.	Co-location Standard.....	195
7.4.	Eligibility of Projects Located in Rural Electric Cooperatives and Municipal Utilities.....	197
7.5.	Types of Community Renewable Generation Projects.....	199
7.6.	Subscriber Requirements.....	200
7.6.1.	Small Subscriber Participation.....	201
7.6.2.	Marketing to Small Subscribers.....	201
7.6.3.	Marketing Claims Related to the Ownership of RECs and Community Renewable Generation Subscriptions.....	205
7.7.	Utility Responsibilities.....	206
8.	Illinois Solar for All Program.....	208
8.1.	Overview	208
8.2.	Design Considerations	208
8.2.1.	Relationship with the Adjustable Block Program	208
8.2.2.	Economic Benefits	209
8.3.	Program Launch.....	211
8.4.	Funding and Budget.....	213
8.4.1.	Renewable Energy Resources Fund Funding Available	213
8.4.2.	Utilities Annual Funding Available.....	216
8.4.3.	Section 16-108(k) Funding.....	217
8.4.4.	Setting Budgets.....	218
8.4.5.	Payment Structure.....	219
8.5.	Programs.....	220
8.6.	Setting Incentive Levels	221
8.6.1.	Low-Income Distributed Generation Incentive.....	222
8.6.2.	Low-Income Community Solar Project Initiative	226
8.6.3.	Incentives for Non-Profits and Public Facilities.....	230
8.6.4.	Low-Income Community Solar Pilot Projects.....	231
8.7.	Providing Guidance and Education.....	233
8.8.	Illinois Solar for All Program Administrator	234
8.9.	Quality Assurance.....	235
8.10.	Coordination with Job Training Programs.....	235
8.11.	Additional Requirements for Approved Vendors.....	237
8.12.	Application Process.....	239
8.12.1.	Project Submissions and Batches	239

8.12.2.	Project Selection for Sub-programs with High Demand.....	240
8.13.	Customer Eligibility.....	241
8.13.1.	Income Guidelines	241
8.13.2.	Determining Income Eligibility.....	244
8.14.	Consumer Protections.....	246
8.15.	Environmental Justice Communities.....	248
8.15.1.	Definitions.....	248
8.15.2.	Approach for Defining Environmental Justice Communities	251
8.15.3.	Environmental Justice Community Designations.....	253
8.15.4.	Environmental Justice Communities 25% Goal	253
8.16.	Program Changes.....	253
8.17.	Evaluation.....	254
8.18.	Grassroots Education Funding	256

Tables

Table 3-1: Utility REC Cost Allocations.....	53
Table 3-2: MidAmerican Applicable Load and RPS Budget before and after Change in Forecast Approach.....	56
Table 3-3: Comparison of MidAmerican’s Applicable Load Using the Generation Forecast before Change and the Proposed Proxy for Determining Applicable Load and Budget	59
Table 3-4: REC Procurement Cost Cap Rate by Utility	60
Table 3-5: Expected New Project REC Deliveries	62
Table 3-6: Ameren Illinois Existing REC Portfolio.....	64
Table 3-7: ComEd Existing REC Portfolio.....	64
Table 3-8: MidAmerican Existing REC Portfolio.....	65
Table 3-9: Utility-Scale REC Portfolio Status.....	65
Table 3-10: Statewide REC Portfolio (By Expected Delivery Date).....	66
Table 3-11: Retail Customer Load Applicable to the Compliance Year	67
Table 3-12: Statewide RPS Goals and Targets	68
Table 3-13: Statewide Overall REC Gap	68
Table 3-14: Statewide Wind and Solar RECs in the Portfolio	69
Table 3-15: Ameren Illinois RPS Budget (\$).....	73
Table 3-16: ComEd RPS Budget (\$).....	73
Table 3-17: MidAmerican RPS Budget (\$).....	74
Table 3-18: Statewide RPS Budget Set Asides (\$).....	74
Table 3-19. Statewide RPS Budget (\$)	75
Table 3-20: Statewide REC Gap and Available RPS Budget.....	76
Table 3-21: Balance of HACP as of August 16, 2021 (\$)	77
Table 3-22: Available ACPs (\$)	77
Table 3-23: Effect on RPS Budget of Annual Load Variations to the Utilities’ Load Forecast.....	81
Table 4-1: Natural Gas-Fired Combined-Cycle Generation Emissions Rates	106
Table 4-2: Wind Duration/Direction Factors.....	107
Table 5-1: Utility-Scale REC Portfolio Status.....	124
Table 5-2: 2018-2021 Forward Procurements Summary.....	127
Table 5-3: New Wind and New Utility-Scale Solar RECs Under Contract and Targets.....	129
Table 5-4: Proposed Procurements	131
Table 5-5: New Wind/Solar RECs Expected Deliveries	132
Table 6-1: Initial Plan Block Volumes (MW)	138
Table 6-2: Block Group REC Prices, 4% Change Between Blocks (\$/REC).....	145
Table 6-3: Updated REC Prices, Preliminary REC Pricing Model Update (\$/REC).....	148
Table 6-4: Current Community Solar Adders.....	151
Table 6-5: Proposed Community Solar Adders.....	152
Table 6-6: Adjustable Block Projects as of August 1, 2021	167
Table 7-1: Federal Statutes that Apply to Community Solar.....	203
Table 7-2: Illinois Statutes that Apply to Community Solar	203
Table 8-1: RERF Funding for Solar for All.....	215
Table 8-2: Utility Funding.....	216
Table 8-3: Total Illinois Solar for All Budgets.....	219

Table 8-4: Incentives for the Low-Income Distributed Generation Program, 1-4 unit buildings (\$/REC)	225
Table 8-5: Incentives for the Low-Income Distributed Generation Program, 5+ unit buildings (\$/REC)	226
Table 8-6: Incentives for Low-Income Community Solar Projects (\$/REC)	229
Table 8-7: Incentives for Non-Profits and Public Facilities (\$/REC)	231
Table 8-8: HUD Income Limits.....	242
Table 8-9: Eligibility Guidelines for LIHEAP and WAP in Illinois.....	243
Table 8-10: Summary of CalEnviroScreen 3.0 Identification Methodology.....	250

Figures

Figure 3-1: Statewide Annual RPS Goal, REC Portfolio and REC Gap	69
Figure 3-2: Projected RPS Spending (As of August 16, 2021).....	75
Figure 3-3: Projected RPS Spending (Based on April 20, 2020 Long-Term Plan)	86
Figure 3-4: Projected RPS Spending (Based on December 18, 2020 Update)	87
Figure 3-5: Projected RPS Spending Changes Over Time	99
Figure 4-1: Pollution Score Calculation.....	108
Figure 4-2: Fuel and Resource Diversity Score	109
Figure 4-3: Reliability and Resiliency Score	110
Figure 4-4: CO ₂ Score Calculation.....	111
Figure 8-1: Springfield Qualified Census Tracts	244
Figure 8-2: CalEnviroScreen Formula.....	252

Appendices

Appendix A: Legislative Compliance Index
Appendix B: Summaries of Goals and Targets, RPS Portfolios, and Budgets
Appendix C: Review of other State REC Pricing Approaches
Appendix D: Renewable Energy Credit Pricing Model Description
Appendix E: Renewable Energy Credit Pricing Models” (spreadsheets)
Appendix F: Income Eligibility Guidelines for Illinois Solar For All
Appendix G: Illinois Solar for All Evaluation Report

Appendices are available separately at:

<https://www2.illinois.gov/sites/ipa/Pages/Second-Revised-LTRRPP-Appendices.aspx>

1. Introduction

This document constitutes the draft for public comment of the Second Revised Long-Term Renewable Resources Procurement Plan (“Second Revised Plan”) of the Illinois Power Agency (“IPA” or “Agency”). While the Agency understands that legislation under consideration by the Illinois General Assembly would include substantial changes to the Illinois Renewable Portfolio Standard (“Illinois RPS” or “RPS”) and, if enacted, may require the development of a new plan under a different planning process, the Agency is releasing this Second Revised Plan to fulfill its statutory obligation under the Illinois Public Utilities Act to update its Long-Term Renewable Resources Procurement Plan (generally, “Plan”) on a biennial basis. The proposed updates contained in this draft Second Revised Plan are informed the current status of RPS budgets, especially the significant funding constraints that preclude most additional programmatic and procurement activities. The Agency remains hopeful that legislative action to address the funding constraints and to make other structural improvements to the RPS will be enacted in the near future.

The Initial Long-Term Renewable Resources Procurement Plan (“Initial Plan”) was developed by the IPA pursuant to the provisions of Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act (“Act” or “IPA Act”), and Section 16-111.5 of the Public Utilities Act (“PUA”). That Initial Plan¹ was developed under authority established through Public Act 99-0906 (“P.A. 99-0906”), enacted December 7, 2016 (effective June 1, 2017), which substantially revised the Illinois Renewable Portfolio Standard (“Illinois RPS” or “RPS”). The Initial Plan covered the Agency’s renewable energy resources procurement and programmatic activities for 2018 and 2019 and was approved by the Commission on April 3, 2018 in Docket No. 17-0838. The Agency published the final Initial Plan on August 6, 2018.

Section 16-111.5(b)(5)(ii)(B) of the PUA provides that “[the Agency] shall review, and may revise, the plan at least every 2 years thereafter.” This process of developing the current revisions to the Plan constitutes the Agency’s second such update. That subparagraph further provides that “[t]o the extent practicable, the Agency shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency’s other planning and approval processes conducted under this Section.” A Long-Term Plan update process was previously undertaken by the Agency, when on August 15, 2019, a draft Revised Plan was released for public comment concurrently with the IPA’s release of its draft 2020 Electricity Procurement Plan. The Revised Plan was filed for Commission approval on October 21, 2019 and reflected the Agency’s consideration of comments received.

Under Section 16-111.5(b)(5)(ii)(C) of the PUA, the Commission then had 120 days to review the Revised Plan and enter its Order confirming or modifying the Plan and the Commission approved that Plan on February 18, 2020 and the Agency published a final version (“First Revised Plan”) on April 20, 2020. The Agency subsequently petitioned the Commission to reopen the First Revised Plan to provide modifications addressing RPS budget issues on March 3, 2021. The Commission approved those modifications on May 27, 2021 and the Agency filed a First Revised Plan on Reopening in conformance with that Order on June 7, 2021.

The Initial Plan addressed the Agency’s proposed set of programs and competitive procurements to acquire renewable energy credits (“RECs”) for RPS compliance obligations applicable to three Illinois

¹ The Initial Plan is available at <https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/Long%20Term%20Renewable%20Resources%20Procurement%20Plan%20%288-6-18%29.pdf>.

electric utilities: Ameren Illinois Company (“Ameren Illinois”), Commonwealth Edison Company (“ComEd”), and MidAmerican Energy Company (“MidAmerican”). The Initial Plan also described how the Agency would develop and implement the Illinois Solar for All (“ILSFA”) Program, which utilizes a combination of funds held by the Agency in the Renewable Energy Resources Fund (“RERF”) and funds supplied by the utilities from ratepayer collections, to support the development of photovoltaic (“PV”) resources, along with job training opportunities (supported separately) to benefit low-income households and environmental justice communities. The First Revised Plan updated those programs and procurements where applicable.

The First Revised Plan covered the Agency’s proposals for procurements and program activity to be conducted during calendar years 2020 and 2021. As discussed throughout that Plan, absent legislative changes, RPS budget limitations would constrain the ability of the Agency to conduct additional procurements or expand program capacity for its Adjustable Block Program. That concern proved accurate, and the Agency has been unable to open additional blocks of capacity for the Adjustable Block Program beyond those envisioned through the Initial Plan as a result. As of the publication of this draft Second Revised Plan for stakeholder comment on August 16, 2021, legislative changes to the RPS are still under consideration by the Illinois General Assembly.

Therefore, this draft Second Revised Plan provides a general framework for changes to procurements and programs should additional funding become available.² However, the Agency recognizes that legislative changes to the RPS may include significant changes to programs and procurements and a subsequent Revised Plan would be required to implement any enacted changes.

Absent legislative changes to the planning cycle, the Agency expects that as part of its annual procurement planning process conducted in calendar year 2023 (for implementation in 2024), it will again update and revise this Plan.

1.1. First Revised Plan Accomplishments

Subsequent to the approval of the First Revised Plan by the Commission on February 21, 2020, the Agency has completed the following implementation activities:

- Block capacity for the Adjustable Block Program filled up (March 2020 for Large Distributed Generation; December 2020 for Small Distributed Generation). Project applications are currently being placed on waitlists.
- The third program year of the Illinois Solar for All Program opened in June 2020. Project applications filled the available funding for the non-profit/public facilities and low-income community solar sub-programs, while project applications in the distributed generation sub-program continued to not meet program goals. The fourth year of the program opened in June 2021.
- A new-wind forward procurement (1 million RECs annually from new utility-scale wind projects) was conducted in March 2021. No projects were selected.

² The Illinois Solar for All Program is not impacted by the same budget constraints as it features somewhat distinct funding sources and prioritization for funding of this program under P.A. 99-0906 as discussed in Chapter 3. Accordingly, this Second Revised Plan proposes updates to the administration of that program.

Additionally, many program materials have been updated (including Marketing Guidelines, Disclosure Forms, the Adjustable Block Program Guidebook, and individual program websites) and the Agency has conducted numerous stakeholder feedback and comment processes.

The ongoing COVID-19 global pandemic significantly contributed to delays in project completions in 2020 and 2021. Nonetheless, as of the release of this draft Second Revised Plan, 88.5% of Small Distributed Generation, 88.2% of Large Distributed Generation, and 32.4% of Community Solar projects from initial Adjustable Block Program blocks have been energized.

1.2. Plan Organization

This draft Second Revised Plan contains eight chapters.

Chapter 1 is this Introduction. It contains a brief overview of the Plan and a set of Action Items that the Agency requested that the Commission expressly adopt as part of its approval of this Revised Plan.

Chapter 2 provides an overview of the legislative/regulatory requirements contained in the Illinois Power Agency Act and the Public Utilities Act (particularly those that result from the enactment of Public Act 99-0906) that led to the development of the Initial Plan, the First Revised Plan and this draft Second Revised Plan, and the implementation of the resulting programs and procurements by the Illinois Power Agency.

Chapter 3 contains calculations of RPS targets, summaries of RPS portfolios, and summaries of RPS budgets. For this draft Second Revised Plan, it provides a discussion of the forecast budget limitations that will constrain activities for the next several years.

Chapter 4 discusses the eligibility of RECs for use in the Illinois RPS. In particular, it addresses two requirements of the RPS: eligibility of RECs from facilities in adjacent states, and the requirement that RECs cannot be procured from facilities that recover their costs through regulated rates.

Chapter 5 describes the competitive procurement process and the procurements the Agency plans to conduct for the delivery of RECs when additional funding becomes available. Procurements considered include procurements for RECs from new brownfield site photovoltaic projects, utility-scale photovoltaic projects, and utility-scale wind projects.

Chapter 6 describes the Adjustable Block Program. This includes details on the structure of the blocks, REC (and adder) prices, the application process, payment terms, the process for adjusting prices, the process for approving vendors, project specifications, consumer protections, delivery requirements, and more. For this Second Revised Plan, the Agency proposes certain adjustments to the program structure contained in the Initial and First Revised Plans.

Chapter 7 describes the Community Renewable Generation Program including standards for co-location, eligibility of projects located in municipal utilities and rural electric cooperatives, subscriber requirements, consumer protections, and the responsibilities of utilities.

Chapter 8 describes the Illinois Solar for All Program including the program funding and design, customer terms, conditions, and eligibility, and an approach to designating environmental justice communities. For this Revised Plan, the Agency proposes certain adjustments to the program structure contained in the Initial and First Revised Plans.

1.3. Action Plan

In this Revised Plan, the IPA recommended the following items for ICC action as part of the Plan's approval:

1. Approve the RPS targets, and budget estimates for Ameren Illinois, ComEd, and MidAmerican for the delivery years 2022-2023 through 2023-2024 contained in Chapter 3, and additionally that Ameren Illinois, ComEd, and MidAmerican will provide updated load forecasts and budget data to the Agency on a biannual basis (each spring and fall) to allow the Agency to update those numbers.
2. Approve the Agency's updated approach to prioritizing the use of any available RPS budget funds as outlined in Chapter 3, as well as the approach for REC delivery contract prioritization and potential REC payment deferrals for the 2022-2023 and 2023-2024 delivery years.
3. Approve the continuation of the Agency's approach for considering and weighting the public interest criteria related to facilities located in adjacent states that is contained in Chapter 4.
4. Approve the proposed procurements contained in Chapter 5.
5. Approve the continuation of the basic design of the Adjustable Block Program contained in Chapter 6, including the block design, schedule of REC prices (and adders), and program terms and conditions as well as the updates proposed in this Second Revised Plan.
6. Approve the continuation of the basic design and terms and conditions of the Community Renewable Generation Program contained in Chapter 7 as well as the updates proposed in this Second Revised Plan.
7. Approve the continuation of the basic design and terms and conditions of the Illinois Solar for All Program contained in Chapter 8 as well as the updates proposed in this Second Revised Plan.

The Illinois Power Agency respectfully publishes this draft Second Revised Long-Term Renewable Resources Procurement Plan and invites interested parties to submit comments on it by September 30, 2021.

2. Legislative/Regulatory Requirements of the Plan

As with the Initial and First Revised Long-Term Plans, this Chapter of the IPA's Revised Long-Term Renewable Resources Procurement Plan describes the legislative and regulatory requirements applicable to the Long-Term Renewables Plan, retaining much of the background discussion from the Initial Plan.

A Legislative Compliance Index, Appendix A, provides a complete cross-index of regulatory/legislative requirements and the specific sections of this Revised Plan that address each requirement identified.

2.1. Renewable Energy Resource Procurement Prior to Public Act 99-0906

Public Act 99-0906 did not introduce a Renewable Portfolio Standard into Illinois law, and the IPA's Long-Term Renewable Resources Procurement Plan is not the first Plan that the Agency produced addressing renewable energy resources procurement. Instead, the Agency has been producing procurement plans addressing renewable energy resource procurements since 2008 and conducting renewable energy resource procurements since 2009, and it is helpful to understand the background of the Illinois RPS's original structure and subsequent challenges in understanding the changes made through P.A. 99-0906 and the choices made through its implementation.

Prior to P.A. 99-0906, the Illinois RPS effectively had three compliance mechanisms depending on a customer's supply source: eligible retail customer procurements, Alternative Retail Electric Supplier ("ARES") compliance, and hourly pricing customer compliance payments. Below is an outline of the pre-P.A. 99-0906 RPS, provided for background; please note that the provisions discussed in Section 2.1 no longer govern RPS implementation and compliance in Illinois.

2.1.1. Original RPS—Eligible Retail Customer Load

Of the three former RPS compliance mechanisms, the compliance pathway that looked most like the revised RPS enacted through P.A. 99-0906 was that which applied to "eligible retail customers," or those customers still taking default supply service from their electric utility (ComEd and Ameren Illinois, and starting in 2015, MidAmerican). The Agency's annual procurement plans (developed primarily to propose procurements intended to meet the energy, capacity, and other standard wholesale product requirements of eligible retail customers) also were required to include procurement proposals intended to meet annually-climbing, percentage-based renewable energy resource targets. As with block energy procured by the Agency, the applicable utility would be the counterparty to any resulting contracts.

Sub-targets were also introduced to the overall procurement volumes: of the renewable energy resources procured, 75% were required to come from wind, 6% from photovoltaics, and 1% from distributed generation. Prior to June 1, 2011, resources from Illinois were expressly prioritized (looking next to adjoining states if none was available, and then to elsewhere); after June 1, 2011, the RPS required looking to Illinois and adjoining states together as a first priority, and then to elsewhere. Funds available for use under RPS contracts were subject to a rate impact cap—a fixed bill impact cap percentage (2.015% of 2007 rates), which was then applied to eligible retail customer load to produce a renewable resources procurement budget.

This system may have worked more effectively had Illinois not experienced significant volatility in the size of its eligible retail customer load. But it did, primarily for the following reason: upon the

establishment of the IPA in 2007, the General Assembly required that the electric utilities enter into relatively long-term energy supply contracts (known as the “swap contracts”) to serve eligible retail customer load. In the years that followed, energy prices plummeted in the wholesale market, and these agreements served to inflate the default supply rate well above that which could be offered by a competitive supplier. From 2011 to 2013, massive waves of default supply customers switched to ARES, often through opt-out municipal aggregation (municipalities, whether individually or in a coalition with others, leveraging economies of scale to negotiate favorable electric supply rates for their residents, under authority of Section 1-92 of the Act), and eligible retail customer load dwindled—with the annual available renewable resources budget declining correspondingly.

As part of its 2009 Annual Procurement Plan, the Agency proposed, and the Commission approved, a procurement for “bundled” (energy and REC) long-term contracts from renewable energy suppliers (known as the Long-Term Power Purchase Agreements, or “LTPPAs”). The LTPPA contracts were executed through a 2010 procurement event, with winning suppliers receiving 20 year bundled contracts to help meet future years’ RPS targets. While this procurement helped facilitate significant new renewable energy development in Illinois (especially in the form of wind projects), it also provided a floor of annual payment obligations under the renewable resources budget for future years.

As the annual renewable resources budget declined due to customer switching, not only was funding unavailable to conduct additional renewable energy resource procurements, funding was no longer available to meet the full commitments of the LTPPAs described above—resulting in two years in which ComEd’s LTPPAs were curtailed, or payment not made through the renewable resources budget for the full expected output. And while some load has switched back to default supply service in recent years, future budget uncertainty made entering into any additional long-term agreements unworkable (especially if such contracts were to be junior in priority to the existing 2010 LTPPAs). Because the Agency could not have visibility into budgets available in future years, outside of targeted distributed generation (“DG”) procurements (which were statutorily required to be at least 5 year contracts), the Agency’s annual procurement plans after the 2010 LTPPAs proposed only the procurement of one-year contracts to meet each upcoming delivery year’s renewable energy resource obligations. As obtaining financing for developing new facilities generally required revenue certainty over a long period, this short-term focus left the prior RPS as an ineffective (or “broken”) tool for facilitating the development of new renewable energy generation.

2.1.2. Original RPS—Hourly Pricing Customers

For hourly pricing customers, Section 1-75(c)(5) of the Act required that the applicable electric utility apply “the lesser of the maximum alternative compliance payment rate or the most recent estimated alternative compliance payment rate for its service territory for the corresponding compliance period” to hourly pricing customers. Those funds were held by the electric utility—and thus not subject to the transfer, sweep, and appropriation risks facing special state funds—and subject to the Agency’s annual procurement planning process.

Because contracts with distributed generation systems required contracts of at least 5 years, the IPA used these hourly Alternative Compliance Payments (“ACPs”) to serve as the funding source for DG procurements, including DG procurements approved in the IPA’s 2017 Annual Procurement Plan.

As discussed more fully in Chapter 3, even accounting for payments still to be made under those DG procurements, some balance of prior-collected hourly ACPs remains for renewable energy resource

procurement under programs and procurements developed under P.A. 99-0906's revisions to Section 1-75(c)(1) of the IPA Act. However, those funds are currently projected to be fully spent (in the case of ComEd) or nearly fully spent (in the case of Ameren Illinois) to meet projected 2021-22 delivery year RPS expenses.³

2.1.3. Original RPS—ARES Compliance

Lastly, adopted in 2009, the ARES RPS compliance mechanism was more complex. Under Section 16-115D of the Public Utilities Act, each ARES carried a percentage-based renewable portfolio standard requirement similar to the Section 1-75(c) requirement as a percentage of its sales, but could satisfy its obligation by making alternative compliance payments at a rate reflecting that rate paid by eligible retail customers for no less than 50% of its obligation. For the remaining 50% of its obligation, the ARES could either pay additional alternative compliance payments and/or self-procure RECs (with a requirement that any RECs procured for compliance be produced by facilities within the regional transmission territories of PJM Interconnection, L.L.C. ("PJM") and Midcontinent Independent System Operator, Inc. ("MISO"), a relatively broad geographic footprint).

With ARES competing with one another for customers (and, for residential and small commercial customers, also competing against default supply service), this paradigm created an incentive for an ARES to comply at the lowest cost possible.⁴ Thus, alternative compliance payments were generally made for the minimum 50% amount (as the rate applicable to those ACPs reflected more expensive procurements made by the Agency to serve other ends, such as through the 2010 LTPPAs), and the self-procurement obligation was not structured to lead to the development of new renewable energy generation.

Alternative compliance payments were deposited into the IPA-administered Renewable Energy Resources Fund. Leveraging this fund for procurements carried significant challenges. As the IPA explained in its Supplemental Photovoltaic Procurement Plan (released in 2014 and approved in 2015):⁵

The procurement of renewable energy resources using the RERF is subject to a set of unique constraints. First, unlike with the utility renewable resources budgets, the RERF may only be used to procure renewable energy credits. While the term "renewable energy resources" is defined in the Illinois Power Agency Act as RECs or both renewable energy and associated RECs,⁶ the Public Utilities Act makes clear that "alternative compliance payments . . . shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund and used to procure renewable energy credits."⁷

Second, Section 1-56(c) of the IPA Act calls on the IPA to use the RERF to "procure renewable energy resources at least once each year in conjunction with a procurement event for electric utilities required to comply with Section 1-75 of the Act."⁸ Given the

³ While any remaining ACP funds (including hourly ACPs and ACPs paid to utilities by ARES) are considered part of the available RPS budget for planning purposes, as funds are already collected, these ACP funds do not count against Section 1-75(c)(1)(E)'s rate impact cap.

⁴ To the extent that a customer sought a more environmentally friendly product, the ARES could always offer a "green" product including 100% of megawatt-hours matched with renewable energy credits, disconnected from any RPS compliance obligation.

⁵ The characterizations of state law in this excerpt refer to the requirements of the Illinois Power Agency Act prior to Public Act 99-0906.

⁶ 20 ILCS 3855/1-10.

⁷ 220 ILCS 5/16-115D(d)(4).

⁸ 20 ILCS 3855/1-56(c).

IPA's strategy of advance purchases to hedge load requirements and the unexpectedly high levels of migration to alternative retail electric suppliers, corresponding energy procurement events for electric utilities had not occurred since 2012.⁹ This has left the Agency without a procurement event "in conjunction with" which it could procure RECs using the RERF.

Third, Section 1-56(d) of the IPA Act requires that "the price paid to procure renewable energy credits" using the RERF "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with Section 1-75 of this Act."¹⁰ The lack of a conjoining procurement event has also left the Agency without a statutorily envisioned price ceiling for "like resources," further constraining procurement using the RERF.

Fourth, the IPA Act clearly articulates a preference for longer-term contracts using the RERF, presumably to provide a stable stream of revenue necessary to incent the development of new resources. Section 1-56(c) of the IPA Act calls for the Agency to, "whenever possible, enter into long-term contracts on an annual basis for a portion of the incremental requirement for the given procurement year."¹¹ Similarly, Section 1-56(b) of the Act requires that any contracts for resources from distributed generation ("DG") must run a minimum of 5 years.¹² But due to unsettled and dynamic load migration between utility and alternative supplier service, the Agency must approach long-term contracting with prudence and care, as the RERF's future balance is subject to the whims of future customer switching.¹³

In addition to the above risks, as a special state fund, the RERF could always be—and indeed was—subject to the risks of borrowing and transfers. In 2010, \$6.7 million was transferred out of the RERF, although ultimately repaid back into it. In 2015, \$98 million was permanently transferred from the RERF to the state's General Revenue Fund ("GRF") to make up for insufficient Fiscal Year 2015 general revenues. And in August 2017, \$150 million was temporarily transferred from the RERF to the GRF (after \$12 million was permanently transferred from the RERF to the state's Public Utilities Fund in June 2017), leaving the RERF's balance temporarily below the level needed to cover existing contractual obligations (\$37.5 million was transferred back into the RERF from the GRF in April 2018).¹⁴ Given these risks, and given recent periods in which the state failed to enact a budget (and thus the IPA lacked appropriation authority to make payments under contracts regardless of actual funds available), the State of Illinois was an unattractive counterparty for REC delivery contracts.

⁹ After not having procured energy in 2013, the Agency did conduct energy procurements in April 2014 and September 2014.

¹⁰ 20 ILCS 3855/1-56(d).

¹¹ 20 ILCS 3855/1-56(c).

¹² 20 ILCS 3855/1-56(b).

¹³ For further discussion of the challenges associated with entering into long-term contracts using funding streams subject to load migration changes, see filings made in Commission dockets approving the IPA's 2013 and 2014 annual procurement plans (Docket Nos. 12-0544 and 13-0546).

¹⁴ The transfer of \$150 million was pursuant to Section 5h.5 of the State Finance Act (30 ILCS 105/5h.5) which authorizes transfers from special funds to the General Revenue Fund for liquidity purposes. As most recently modified by Public Act 102-0016, that Section also contains a provision that funds will be repaid within "60 months after the date on which they were borrowed," and a provision to transfer borrowed funds back to that special fund in "only such amount as is immediately necessary to satisfy outstanding expenditure obligations on a timely basis."

With the majority of Illinois electric load being served by ARES, this stood as no small problem—while the RPS technically covered the vast majority of electricity delivered in the state, very little new renewable generation was able to be developed through it. Significant amounts were being paid into the RERF each year to support renewable energy development, yet the money was unable to be effectively leveraged for that purpose. While ARES were procuring millions of RECs in aggregate each year, the incentive structure facing those suppliers made it highly unlikely that those RECs would be sourced from anything other than the lowest-priced seller: generally, facilities already built and financed, and potentially from projects in vertically integrated states with costs already being fully recovered through rates. Hence, parties seeking changes to this system often characterized the Illinois RPS as a “broken RPS,”¹⁵ and one that would require a comprehensive legislative overhaul to be properly fixed.

2.2. Public Act 99-0906

The Agency’s obligation to develop a Long-Term Renewable Resources Procurement Plan stems from requirements included in Public Act 99-0906, known colloquially as the “Future Energy Jobs Act” and referred to herein as P.A. 99-0906. P.A. 99-0906, was passed by both the Illinois House and Senate during the last days of the 99th General Assembly on December 1, 2016, and was signed into law on December 7, 2016 with an effective date of June 1, 2017.

In addition to the requirement that the Agency develop its Long-Term Renewable Resources Procurement Plan and implement the programs and procurement discussed herein, P.A. 99-0906 also contained other significant reforms to Illinois energy law. Among those reforms included the establishment of a zero emission standard requiring the Agency to develop a Zero Emission Standard Procurement Plan for the procurement of zero emission credits from zero emission (i.e., nuclear) generating facilities;¹⁶ revisions to the state’s energy efficiency portfolio standard found in Article VIII of the Public Utilities Act (220 ILCS 5) including the adoption of cumulative savings targets for energy efficiency programs and measures, and the elimination of the statutory pathway by which incremental energy efficiency programs were included in the IPA’s annual procurement plans;¹⁷ additional financial assistance for low-income ratepayers;¹⁸ bill crediting for the energy production associated with subscriptions to community renewable generation;¹⁹ and a smart inverter rebate for behind-the-meter generating facilities.²⁰

More pertinently for purposes of this Plan, P.A. 99-0906 constituted a comprehensive overhaul of the state’s renewable energy portfolio standard, elements of which can be found in Sections 1-56 and 1-75(c) of the IPA Act and Section 16-115D of the PUA. Under the prior Illinois RPS, compliance and

¹⁵ One notable success story from the RERF was the Supplemental Photovoltaic Procurement process, which resulted in the development of roughly 30 MW of new distributed generation photovoltaics in Illinois through five-year REC contracts using the RERF. But even this process required legislative changes to be effectuated, with the Agency’s authority to develop its Supplemental Photovoltaic Procurement Plan coming from Public Act 98-0672 (signed into law in 2014), which created new Section 1-56(i) of the IPA Act.

¹⁶ The Agency’s Zero Emission Standard Procurement Plan, developed pursuant to new Section 1-75(d-5) of the Act, was filed with the Commission on July 31, 2017 and was approved by the Commission on September 11, 2017. See ICC Docket No. 17-0333.

¹⁷ See 220 ILCS 5/16-111.5B.

¹⁸ See 220 ILCS 5/8-103B(c) (requiring ComEd and Ameren Illinois to allocate \$25 million and \$8.5 million, respectively, annually for low-income energy efficiency programs); 305 ILCS 20/18(c)(5), (5.5), (7) (authorizing Percentage of Income Payment Plan (“PIPP”) qualified customers to receive credits under a utility’s Arrearage Reduction Program, and creating a new Supplemental Arrearage Reduction Program for utility customers who cannot join the PIPP due to timing or funding constraints); 220 ILCS 5/16-108.10 (creating new \$10 million annual funding stream over five years for low-income assistance programs for ComEd customers).

¹⁹ See 220 ILCS 5/16-107.5(I).

²⁰ See 220 ILCS 5/16-107.6.

planning depended on how a customer's supply requirements were met, with three separate compliance mechanisms for by default utility supply service, hourly-pricing customers, and load served by Alternative Retail Electric Suppliers. As discussed further below, changes to the Illinois RPS through P.A. 99-0906 have now fully transitioned the state's RPS to a streamlined, centralized planning and procurement process, with both RPS targets and available budgets determined on the basis of an electric utility's load for all retail customers²¹ with funding collected through a delivery services charge. The state's approach to meeting its RPS targets is now addressed through the initial development and continued refinement of this Long-Term Renewable Resources Procurement Plan, with the Plan proposing programs and procurements necessary to meet the new requirements of Illinois law and satisfying the law's new emphasis on both using the RPS as a tool to facilitate the development of new generating facilities and expanding access to the benefits of renewable energy across a broader cross-section of the state's economy.

2.2.1. Legislative Findings

This new emphasis was reflected in the legislative findings associated with Public Act 99-0906. Specifically, in enacting P.A. 99-0906, the General Assembly found that "[t]o ensure that the State and its citizens, including low-income citizens, are equipped to enjoy the opportunities and benefits of the smart grid and evolving clean energy marketplace," P.A. 99-0906 should serve to "maximize the impact" of the state's RPS.²² This includes direction that the State should "encourage . . . the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households."²³

These themes are also found in the legislative findings and declarations of the IPA Act enacted through P.A. 99-0906. The IPA Act now finds and declares that "[d]eveloping new renewable energy resources in Illinois, including brownfield solar projects and community solar projects, will help to diversify Illinois electricity supply, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents."²⁴ Other findings also reinforce the value of community solar in expanding access to renewable energy,²⁵ and the value of developing brownfield site solar projects to "help return blighted or contaminated land to productive use while enhancing public health and the well-being of Illinois residents."²⁶

This approach to the state's RPS was a meaningful shift in the logic governing the state's renewable energy requirements: prior to 2017, the state's approach to its RPS could have been understood as governed by the logic that statutory compliance should be achieved at "the lowest total cost over

²¹ For MidAmerican, the IPA understands that Section 1-75(c)'s renewable energy procurement targets are generally applied to the supply procured for MidAmerican's jurisdictional eligible retail customers and not all retail sales in its service territory.

²² P.A. 99-0906, § 1(a).

²³ P.A. 99-0906, § 1(a)(1). In the legislative findings of P.A. 99-0906, the General Assembly also specifically found that "low-income customers should be included within the State's efforts to expand the use of distributed generation technologies and devices." P.A. 99-0906, § 1(b).

²⁴ 20 ILCS 3855/1-5(6).

²⁵ 20 ILCS 3855/1-5(7).

²⁶ 20 ILCS 3855/1-5(8).

time, taking into account any benefits of price stability,”²⁷ as this criteria governed the Agency’s annual procurement plan, in which renewable energy procurements were proposed. Through changes effected by P.A. 99-0906, state law now seeks outcomes of specific types—more equitable and diverse access to the benefits of renewable energy, and an emphasis on facilitating the development of new generation and maximizing its environmental benefits—in achieving compliance with the technical requirements of the law.

Guidance found in the RPS law itself also reflects that approach. Specifically, Section 1-75(c)(1)(I) of the IPA Act requires that the IPA “shall design its long-term renewable energy procurement plan to maximize the State’s interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State.” The Agency believes its Initial, Revised, and now Second Revised Long-Term Renewable Resources Procurement Plans reflect these aspirations.

2.2.2. Changes to the RPS

Public Act 99-0906 also ushered in several changes to the RPS, including the introduction of new concepts, terms, and prescriptive requirements. As was done in the Initial Plan and First Revised Plan, several of these concepts are discussed below, in the subsections later in this chapter, and in the Chapters that follow.

2.2.3. Concepts and Terms

First, as discussed further below, P.A. 99-0906 demonstrated a shift in compliance focus from compliance through the procurement of “renewable energy resources”—which may be either 1) a renewable energy credit associated with a megawatt-hour (“MWh”) of generation, or 2) that REC plus the associated generation—to compliance through the purchase and retirement of “renewable energy credits.”²⁸ This change makes intuitive sense; the purchase of energy is not addressed through this planning process, and the Agency’s planning for any energy purchases can only be for utility default supply customers (“eligible retail customers”) through the development of a separate procurement plan (which focuses on a shorter timeframe than many of the REC contracts envisioned in the revised RPS).

Second, P.A. 99-0906 introduced the concept of a “community renewable generation project” to Illinois law. As defined by the IPA Act,²⁹ this is an electric generating facility that

- (1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;

²⁷ See 220 ILCS 5/16-111.5(d)(4).

²⁸ See, e.g., 20 ILCS 3855/1-75(c)(1)(B), (C). The law continues to recognize that “renewable energy resources” may be used to satisfy the RPS, but focuses this Plan only on the procurement of “renewable energy credits” (which, standing alone, also may constitute “renewable energy resources”).

²⁹ See 20 ILCS 3855/1-10.

(2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act;

(3) credits the value of electricity generated by the facility to the subscribers of the facility; and

(4) is limited in nameplate capacity³⁰ to less than or equal to 2,000 kilowatts.

A subscriber's subscription to such a facility is an "interest" in that facility, "expressed in kilowatts" and sized primarily to offset part or all of the subscriber's electricity usage, and may not constitute more than 40% of the facility's nameplate capacity.³¹ Photovoltaic powered community renewable generating projects are frequently described herein (as well as in Sections 1-10 and 1-56(b) of the IPA Act) as "community solar" projects, and to ensure that such projects are developed, community solar projects have distinct minimum procurement targets in the Illinois RPS.

Third, P.A. 99-0906 requires the development and ongoing operation of an "adjustable block program" ("ABP"). Used to facilitate the development of new community solar and distributed photovoltaic generation, the Adjustable Block Program must feature a "transparent schedule of prices and quantities" for RECs "to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time."³² This pricing approach represented a significant shift in the state's approach to procuring renewable energy; prior to the ABP (and to the Illinois Solar for All Program), past efforts to procure renewable energy resources focused on competitive sealed bidding, pay-as-bid procurement events. Most bidder and supplier information, including resulting contract prices and quantities for winning bidders, was considered confidential. While these competitive procurement elements continue to be utilized for other activities under the Illinois RPS (including "forward procurements"), the Adjustable Block Program (and most categories within the Illinois Solar for All Program) provide open application to a program featuring price and quantity transparency.

Fourth, both the Illinois Solar for All Program and the Adjustable Block Program require "prepayment" (or partial prepayment) for a stream of RECs to be delivered over the course of a 15-year contract. This likewise constituted a departure from prior activities under the Illinois RPS, all of which featured payment for RECs only upon delivery and invoice.

This, of course, is not a comprehensive list of changes; many other new terms and concepts were also introduced through P.A. 99-0906. This non-exhaustive list is intended only to provide context for the discussions that follow.

2.2.4. Long-Term Renewable Resources Procurement Plan

As referenced above, P.A. 99-0906 required that the IPA develop a Long-Term Renewable Resources Procurement Plan. That original Long-Term Renewable Resources Procurement Plan or "Initial Plan" was filed with the Illinois Commerce Commission on December 4, 2017 and approved by the Commission on April 3, 2018 through Docket No. 17-0838. As that plan is required by law to be

³⁰ "Nameplate capacity" is defined in the law as the aggregate inverter nameplate capacity in kilowatts AC. 20 ILCS 3855/1-10.

³¹ Id.

³² 20 ILCS 3855/1-75(c)(1)(K).

updated at least every two years, a First Revised Long-Term Renewable Resources Procurement Plan was approved by the Commission on February 18, 2020 through Docket No. 19-0995.

This separate, renewable energy-focused planning process was a departure from past practice under the Illinois RPS; previously, Illinois law required that renewable energy resource procurements used to meet the requirements of Section 1-75(c) of the IPA Act be proposed through the Agency’s annual procurement plan developed pursuant to Section 16-111.5 of the PUA. As required under Section 16-111.5, those plans were developed, published, filed with the ICC, and approved by the ICC on an annual basis (and still are, with a more limited focus) with a planning horizon of the five upcoming delivery years.

By contrast, the Long-Term Renewable Resources Procurement Plan—prepared pursuant to Section 16-111.5(b)(5) of the PUA, introduced through P.A. 99-0906—was initially prepared in 2017, was approved by the ICC in 2018, is to be revised at least every two years, and “shall include procurement programs and competitive procurement events necessary to meet the goals”³³ set forth in Section 1-75(c) of the IPA Act—which contains annual targets out until 2030.

2.2.5. Plan Requirements

While Illinois law lacks any single list of required elements for the Plan, both Section 16-111.5(b) of the PUA and Sections 1-56(b) and 1-75(c) of the IPA Act contain discrete requirements.

2.2.5.1. Section 16-111.5(b) Requirements

Section 16-111.5(b)(5) of the PUA provides that “[t]he Agency shall prepare a long-term renewable resources procurement plan for the procurement of renewable energy credits under Sections 1-56 and 1-75 of the Illinois Power Agency Act for delivery beginning in the 2017 delivery year,”³⁴ with “delivery year” defined as “the consecutive 12-month period beginning June 1 of a given year and ending May 31 of the following year”³⁵—i.e., the first delivery year for which the Plan was developed was 2017-2018. As a consequence, the IPA’s Initial Plan as filed proposed procurements necessary to meet “2017 delivery year” goals, as well as targets for future delivery years. However, as discussed further in Chapter 5,³⁶ the Commission’s Order in Docket No. 17-0838 directed that no procurements be held to meet Section 1-75(c)(1)(B) of the Act’s 2017 delivery year percentage-based renewable energy credit procurement goals.³⁷ Given the ongoing RPS budget constraints described more thoroughly in Chapter 3, the IPA does not propose additional procurements specifically designed to meet upcoming years’ Section 1-75(c)(1)(B)’s annual percentage-based REC procurement goals through this Second Revised Plan.

The PUA also contains three discrete requirements for what the Plan must contain:

First, the Plan must “[i]dentify the procurement programs and competitive procurement events consistent with the applicable requirements of the Illinois Power Agency Act and shall be designed

³³ 20 ILCS 3855/1-75(c)(1)(A).

³⁴ 220 ILCS 5/16-111.5(b)(5).

³⁵ 20 ILCS 3855/1-10.

³⁶ See generally the discussion of “Spot Procurements.”

³⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 42.

to achieve the goals set forth in subsection (c) of Section 1-75 of that Act.”³⁸ While the term “competitive procurement event” is not specifically defined in the IPA Act or the PUA, the IPA understands the term “competitive procurement event” to be an element of, if not commensurate with, a “competitive procurement process” or “competitive bid process,” which the PUA describes subject to the requirements of Section 16-111.5(e)-(i) where applicable (i.e., conducted in a manner consistent with the Agency’s prior competitive procurements).³⁹ The term “program” presumably refers to the programs specifically referenced in Section 1-56(b) and Sections 1-75(c)(1)(K) and (N) of the IPA Act.

As with the Initial Plan and First Revised Plan, this Second Revised Plan’s specific procurement programs and procurement events designed to meet the goals of Section 1-75(c) can be found in Chapters 5 through 8. However, as discussed throughout this Second Revised Plan, ongoing RPS budget constraints serve to significantly limit additional program and procurement activity.

Second, the Plan must “[i]nclude a schedule for procurements for renewable energy credits from utility-scale wind projects, utility-scale solar projects, and brownfield site photovoltaic projects consistent with subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act.”⁴⁰ This subparagraph concerns the quantitative procurement targets for RECs from new solar and wind facilities found in Section 1-75(c), and the schedule for those procurements can be found in Chapter 5.

Third, the Plan must “[i]dentify the process whereby the Agency will submit to the Commission for review and approval the proposed contracts to implement the programs required by such plan.”⁴¹ Under the prior RPS, pursuant to Section 16-111.5(e) of the PUA, the IPA’s procurement administrator developed standard contract forms in consultation with other parties. A Commission decision was required only if parties could not agree on the contract form, and the standard form contract was required to be executed by winning bidders after a competitive procurement result (the results of which were subject to Commission approval). Under this revised model for use in implementing programs, both REC delivery contracts and the IPA’s program administrator contracts⁴² must first be approved by the Commission prior to execution.⁴³ The IPA’s process for submitting contracts to the Commission for review and approval can be found in Chapters 6 and 8 of the Plan; it does not meaningfully differ from that which was proposed in the Initial Plan and First Revised Plan. As this requirement concerns only “the programs required by such plan,” this requirement does not impact the contract development process for the competitive procurements described in Chapter 5, although Commission approval is also required prior to the execution of contracts for competitive procurements under the process described in Section 16-111.5(e)-(i).

³⁸ 220 ILCS 5/16-111.5(b)(5)(ii)(B)(aa).

³⁹ 220 ILCS 5/16-111.5(b)(5)(iii).

⁴⁰ 220 ILCS 5/16-111.5(b)(5)(ii)(B)(bb).

⁴¹ 220 ILCS 5/16-111.5(b)(5)(ii)(B)(cc).

⁴² For the Agency’s third-party program administrators, Section 16-111.5(b)(5)(iii) provides that “[t]hird parties shall not begin implementing any programs or receive any payment under this Section until the Commission has approved the contract or contracts under the process authorized by the Commission in item (D) of subparagraph (ii) of paragraph (5) of this subsection (b) and the third party and the Agency or utility, as applicable, have executed the contract.”

⁴³ In its Order approving the Initial Plan, the Commission held that under Section 16-111.5(b)(5)(iii)’s requirements, “it must review the individual [REC delivery] contracts between the utilities and Approved Vendors and “not just a master contract, although “a master contract that is updated by a confirmation agreement providing the batch details regarding seller, buyer, price, term, project location, etc. is a reasonable approach.” Docket No. 17-0838, Final Order dated April 3, 2018 at 116.

2.2.5.2. Section 1-75(c) Requirements

Section 1-75(c) of the IPA Act contains the most robust set of requirements for the long-term plan; those include the following:

First, the Plan must “include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter.”⁴⁴ These percentages are described as a portion of eligible retail sales, which now includes sales by alternative retail electric suppliers. The law also contains a requirement that “in the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements,” the long-term plan shall prioritize the new wind and photovoltaic requirements.⁴⁵

In Docket No. 17-0838, the Commission’s Order approving the Initial Plan determined that any procurements originally proposed to meet annual percentage-based renewable energy credit procurement goals should be cancelled to avoid any potential conflicts with meeting “statutory long-term new build requirements.”⁴⁶ As budget constraints have become a more acute concern given the massive progress in new renewable energy development spurred on by programs and procurements conducted under the Initial Plan (and corresponding budget impacts from REC delivery contracts), this Revised Plan has been designed in a manner that likewise focuses on supporting new projects. Further discussion can be found in Chapter 3.

Second, the Plan “shall include the procurement of renewable energy credits in amounts equal to at least” the new wind and new photovoltaics targets found in Section 1-75(c)(1)(C) of the IPA Act. These targets are 2 million RECs from “new wind projects” by the 2020 delivery year, 3 million by 2025, and 4 million by 2030. “New photovoltaic projects” feature the same overall procurement targets, while also containing requirements that at least 50% of new PV RECs be procured through the Adjustable Block Program (and thus from distributed generation or community solar projects), at least 40% from utility-scale (above 2 MW) photovoltaic projects, and at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects. Further discussion of these quantitative new build targets, including a discussion of progress made toward meeting these targets to date, can be found in Chapters 3 and 5.

Third, the law requires that, to the extent that annual RPS spending budgets⁴⁷ for each utility become a binding constraint, the Plan “shall prioritize compliance with the requirements of this subsection (c) regarding renewable energy credits” in the manner discussed in Section 1-75(c)(1)(F), which features the following priority ranking:

(i) renewable energy credits under existing contractual obligations;

(i-5) funding for the Illinois Solar for All Program as described in Section 1-75(c)(1)(O);⁴⁸

⁴⁴ 20 ILCS 3855/1-75(c)(1)(B).

⁴⁵ Id.

⁴⁶ Docket No. 17-0838, Final Order dated April 3, 2018 at 42.

⁴⁷ The statutory cost cap and resulting budgets for RPS spending, directed in Section 1-75(c)(1)(E) of the Act, are discussed in more detail in Section 2.4.4 and Chapter 3 of this Revised Plan.

⁴⁸ This requirement is discussed further in the subsection below.

(ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements in Section 1-75(c)(1)(C); and

(iii) renewable energy credits necessary to meet the remaining requirements of Section 1-75(c) (including the percentage-based delivery year goals in Section 1-75(c)(1)(B)).⁴⁹

This statutory language and related considerations were placed at issue in the Reopening of Docket No. 19-0995, the proceeding for Commission approval of the First Revised Long-Term Plan. Through the IPA's March 3, 2021 Petition on Reopening, the Agency sought for the Commission to approve a regime under which REC delivery contract payments may be subject to deferral should expenses exceed collections for an upcoming delivery year, as the IPA expects will be the case for two of the three utilities in the 2021-22 delivery year. Relying in part on Section 1-75(c)(1)(F), the IPA argued that REC delivery contracts pre-dating Public Act 99-0906's passage and Illinois Solar for All contracts should be exempted from any payment deferrals, as those contracts feature statutory priority. In its May 27, 2021 Order on Reopening, the Commission agreed.⁵⁰

IPA is committed to ensuring that this priority ranking found in Section 1-75(c)(1)(F) is properly reflected in this Second Revised Plan and has assembled its Plan cognizant of and sensitive to this prioritization. Further discussion of contract prioritization for purposes of payment deferrals can be found in Chapter 3.

Fourth, the law requires that renewable energy credits procured under the Initial Forward Procurements shall be included in the Agency's long-term plan and shall apply to Section 1-75(c)'s goals.⁵¹ The results of the Initial Forward Procurements, conducted in three events from August 2017 through April 2018, are reflected in the Agency's target procurement quantities found later in Chapter 3 of this Revised Plan.

Fifth, the Plan must set forth the process by which adjustments may be made when the cumulative amount of renewable energy credits projected to be delivered from all new wind projects in a given delivery year exceeds the cumulative amount of renewable energy credits projected to be delivered from all new photovoltaic projects in that delivery year by 200,000 or more renewable energy credits.⁵² This provision is presumably intended to provide some balancing between wind and solar quantities under contract.

In its Order approving the Initial Plan, the Commission clarified that this balancing requirement becomes effective as of June 1, 2021, the original statutory deadline for deliveries from projects having initial forward procurement contracts (and not earlier, as argued by some parties in Docket No. 17-0838).⁵³ Since that time, Public Act 101-0113—signed into law on July 19, 2019—modified Sections 1-75(c)(1)(G)(i)-(ii) of the IPA Act such that these subparagraphs now provide that should an initial forward procurement project have “delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract,” this statutory deadline may be extended to June 1, 2022. This would

⁴⁹ 20 ILCS 3855/1-75(c)(1)(F).

⁵⁰ See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 26-28.

⁵¹ 20 ILCS 3855/1-75(c)(1)(G)(i).

⁵² 20 ILCS 3855/1-75(c)(1)(G)(iv).

⁵³ See Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

also then extend the effective date of the wind/solar balancing requirement outlined in Section 1-75(c)(1)(G)(iv) of the Act to June 1, 2022.⁵⁴

Sixth, the Plan must describe in detail how each “public interest factor” enumerated in Section 1-75(c)(1)(I) “shall be considered and weighted for facilities located in states adjacent to Illinois” in determining whether those facilities’ RECs may be considered “eligible” to satisfy the Illinois RPS. This limitation of eligible RECs to Illinois and adjacent states constitutes a departure from pre-P.A. 99-0906 practice under the RPS, under which competitive procurements first looked to RECs from Illinois and adjoining states and then to “elsewhere” in attempting to satisfy targets, and may serve to significantly limit the pool of renewable energy credits eligible to meet the RPS. The Agency’s approach for applying these criteria can be found in Chapter 4; it does not differ materially from that which was proposed in its Initial Plan and approved by the Commission in Docket No. 17-0838 and again in Docket No. 19-0995.

Seventh, the Plan shall provide that renewable energy credits previously allocated from generating systems previously understood not to be rate-based for a state-regulated entity, but which end up being so rate-based, shall be made up through a procurement conducted in the Agency’s next procurement event. This connects back to a statutory requirement that “renewable energy credits shall not be eligible to be counted toward” RPS targets “if they are sourced from a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017.”⁵⁵ It appears that this could be accomplished through an adjustment in procurement volumes for subsequent procurement events, and the IPA commits through this Second Revised Plan to make any such adjustments. To date, the IPA is unaware of any instances for which this provision (which is reflected in all program and procurement contracts) has needed to be enforced.

Eighth, the Plan “shall include an Adjustable Block program for the procurement of renewable energy credits from new photovoltaic projects that are distributed renewable energy generation devices or new photovoltaic community renewable generation projects.”⁵⁶ A description of the Agency’s Adjustable Block Program, which has been open for project applications since January 30, 2019, and any proposed adjustments thereto, can be found in Chapter 6, with detailed discussion of community solar-specific requirements also found in Chapter 7.

Ninth, and last among the requirements found in Section 1-75(c), the Plan “shall include a community renewable generation program,” with a requirement that the Agency “establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties” and that any subscriptions to such projects “be portable and transferable.”⁵⁷

Because community solar is a subset of “community renewable generation projects”—which can include generating technologies such as wind, solar thermal, biodiesel, biomass, tree waste, and

⁵⁴ This IPA proposed this approach in its First Revised Long-Term Procurement Plan; it was uncontested in Docket No. 19-0995.

⁵⁵ 20 ILCS 3855/1-75(c)(1)(J).

⁵⁶ 20 ILCS 3855/1-75(c)(1)(K).

⁵⁷ 20 ILCS 3855/1-75(c)(1)(N).

hydropower—*only* establishing an Adjustable Block Program featuring a community solar component would not satisfy this statutory requirement.⁵⁸ For a *non-PV* community renewable generation program, the IPA’s Initial Plan set out a competitive procurement event with bids selected on the basis of price. This procurement event was held in late 2019 and no bids were selected.⁵⁹

2.2.5.3. Illinois Solar for All Requirements

As discussed further below, in recognition of a finding that “the State should encourage . . . investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households,” revisions to Section 1-56 of the IPA Act requires the creation of “the Illinois Solar for All Program, which shall include incentives for low-income distributed generation and community solar projects [. . .] to bring photovoltaics to low-income communities in this State.”⁶⁰ In so doing, the Agency must “include a description of its proposed approach to the design, administration, implementation and evaluation of the Illinois Solar for All Program” in the Plan and “propose the Illinois Solar for All Program terms, conditions, and requirements,”⁶¹ including REC prices (which may be through a formula).

The Illinois Solar for All Program began accepting project applications on May 15, 2019. A more comprehensive description of the Agency’s Illinois Solar for All Program, including any revisions made thereto, can be found in Chapter 8.

In addition to describing what the Illinois Solar for All Program is and how it will be administered, the law also requires that should the IPA hire a third-party program administrator (or administrators) to assist with the administration of the Illinois Solar for All Program, the Plan shall identify at what interval it must report to the Agency and the Commission (provided that interval is at least quarterly). After an RFQ/RFP process, the IPA retained Elevate Energy to administer the Illinois Solar for All Program in September 2018. The Plan shall also provide for an independent evaluation of the program, and must contain a definition of the term “environmental justice” community. After a similar RFQ/RFP process, the IPA retained APPRISE, Inc. to serve as the Illinois Solar for All Program’s independent evaluator in August 2019. The evaluator’s recommendations are discussed in Section 8.16 and are reflected in proposed changes contained in this draft Second Revised Plan. A full evaluation report is contained in Appendix G.

The Plan must also ensure that the Illinois Solar for All program is funded. Specifically, Section 1-75(c)(1)(O) of the Act provides that the Plan “shall allocate 5% of the funds available under the plan for the applicable delivery year, or \$10,000,000 per delivery year, whichever is greater, to fund the programs.” The IPA understands that the intention of this language in Section 1-75(c)(1)(O) is that 5% of utility-collected funds, or \$10 million, whichever is greater, would be made available annually for Illinois Solar for All—in addition to whatever may be spent in a given year through the RERF.

⁵⁸ More specifically, Section 1-75(c)(1)(N) provides that “[t]he Agency shall purchase renewable energy credits from subscribed shares of photovoltaic community renewable generation projects **through the Adjustable Block program** described in subparagraph (K) of this paragraph (1) or through the Illinois Solar for All Program described in Section 1-56 of this Act” (emphasis added). (As the IPA cannot be the counterparty to REC delivery contracts under Section 1-75(c), the Agency understands “purchase” effectively to mean “procure” in this context.)

⁵⁹ More information about the community renewable generation procurement can be found here: <https://www.ipa-energyvrfp.com/2019-community-renewable-generation-program-forward-procurement-aic-and-comed>.

⁶⁰ 20 ILCS 3855/1-56(b)(2).

⁶¹ 20 ILCS 3855/1-56(b)(4).

Notwithstanding the language discussed in the paragraph above, the law also requires that for each of three particular delivery years—“the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025”—the Plan “shall allocate 10% of the funds available under the plan for the applicable delivery year, or \$20,000,000 per delivery year, whichever is greater,” and \$10,000,000 of such funds shall be used by ComEd to implement its Commission-approved workforce development plan filed under Section 16-108.12 of the PUA.⁶² Under the Commission’s Order on Reopening in Docket No. 19-0995, both this annual delivery year ILSFA budget allocation and this job training program funding allocation is given priority and not subject to non-payment, reduction, or deferral in the case of RPS budget constraints, such as those expected to be felt in the 2021-22 delivery year.

If additional funding for Illinois Solar for All programs is available under Section 16-108(k)⁶³ of the PUA, then the Plan “shall provide for the Agency to procure contracts in an amount that does not exceed the funding,” with the applicable utility or utilities as the counterparty to such contracts.⁶⁴ The IPA filed its Illinois Solar for All Supplemental Funding Plan for approval with the Illinois Commerce Commission on August 30, 2018. That Plan concluded as follows regarding whether to use any funding shortfall to provide additional funding for the Illinois Solar for All Program:

Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA’s annual RRB allocation, the legally-required availability of RERF funds previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)’s requirement that the RERF “shall not be subject to sweeps, administrative charges, or chargebacks,” and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.⁶⁵

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457. The Supplemental Funding Plan did note, however, that the Agency would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF’s balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.⁶⁶ While RERF funds have been subject to borrowing since that time, that borrowing has only occurred with the condition that borrowed funds a) will be available for use when expenses become due and b) will eventually be repaid back into the RERF.⁶⁷

2.2.6. Items Not Included in Long-Term Renewable Resource Procurement Plan

While the Plan sets forth the IPA’s proposed approach to meeting the state’s renewable energy resource procurement targets, it is not the sole mechanism for facilitating the development of renewable energy in Illinois or providing value for the environmental attributes of electricity

⁶² 20 ILCS 3855/1-75(c)(1)(O). See also Docket No. 17-0332, in which ComEd’s Workforce Development Implementation Plan was approved.

⁶³ Up to one-half of excess collections by utilities for RPS purposes in each of the 2017-2018, 2018-2019, and 2019-2020 delivery years may be used for the Solar for All Program in the event of a “funding shortfall.” 220 ILCS 5/16-108(k).

⁶⁴ 220 ILCS 5/16-108(k).

⁶⁵ Final Illinois Solar for All Supplemental Funding Plan, dated November 26, 2018, at 30.

⁶⁶ See *id.* at 31.

⁶⁷ See 30 ILCS 105/5h.5.

generation. Thus, many items that may be of interest to readers of this Revised Plan are not directly addressed in this Plan, and below is a non-exhaustive list of those items not addressed in the Plan:

- Contracts or tariffs for the sale of energy from renewable energy generating facilities, whether through bilateral contracts, wholesale market sales, community renewable generation bill crediting, or net metering;
- Previously effective renewable energy resource procurement obligations applicable to alternative retail electric suppliers under Section 16-115D of the PUA;
- The procurement of zero emission credits from zero emission facilities (i.e., nuclear generating facilities) under Section 1-75(d-5) of the IPA Act;
- Workforce development plans produced by a utility pursuant to Section 16-108.12 of the PUA;
- Renewable energy generating device installer certification requirements developed pursuant to Section 16-128A of the PUA;
- Renewable energy provider supplier diversity goals under Section 5-117(b) of the PUA;
- Tariff filings or modifications for the collection of funds used by utilities to pay for renewable energy credit and zero emission credit delivery contracts;
- Specific renewable energy generating projects, proposals, or sites, including any municipal, county, or non-IPA state permitting required;
- “Green” or “clean energy” retail supply products marketed and sold by alternative retail electric suppliers;
- Requirements and processes for the interconnection of new renewable energy generating facilities, including projects facilitated by IPA-administered programs and procurements.

These issues may indeed be of significant interest to the Agency, and in some cases, their presence or resolution informed decisions made in this Revised Plan. However, as they do not fall within the scope and jurisdiction of what the IPA may propose and the Commission may approve as part of this Revised Plan, specific proposals related to the above-listed topics are not made within this document.

2.2.7. Revised Plan Development and Approval

The Initial Plan was released by the Agency as a draft on September 29, 2017, filed with the Commission for approval after public comments and revisions on December 4, 2017, and approved by the Commission on April 3, 2018 via Docket No. 17-0838.

Section 16-111.5(b)(5) of the PUA provides that the Agency “shall review, and may revise, the plan at least every 2 years” after the initial Plan. Further, “[t]o the extent practicable, the Agency shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency’s other planning and approval processes”⁶⁸ conducted under Section 16-111.5 of the PUA. The Agency understands this to refer to the annual procurement plan development and approval process referenced in Section 16-111.5(d).⁶⁹

⁶⁸ 220 ILCS 5/16-111.5(b)(5)(ii)(B).

⁶⁹ Section 1-75(c)(1)(A) of the Act contains a similar provision, stating that “[t]he Agency shall review, and may revise on an expedited basis, the long-term renewable resources procurement plan at least every 2 years, which shall be conducted in conjunction with the procurement plan under Section 16-111.5 of the Public Utilities Act to the extent practicable to minimize administrative expense.”

The First Revised Plan was released on August 15, 2019, filed with the Commission for Approval on October 21, 2019, and was approved by the Commission on February 18, 2020 via Docket No. 19-0995.

This draft Second Revised Plan was published on Monday August 16, 2021 (within two years of its First Revised Plan's publishing). Under the requirements of Section 16-111.5(b)(5)(ii) of the PUA, parties are allowed 45 days to provide comment, resulting in a comment deadline of Thursday, September 30, 2021.

During the comment period, the Agency is also required to hold public hearings for receiving public comment on the Plan in the service territory of each affected utility. Given the uncertainty around the ongoing COVID-19 global health pandemic, the Agency will be conducting those public hearings virtually using Zoom. Those public hearings will be held on Friday, September 3, 2021 for all three affected utility service territories and will be conducted jointly with hearings on the IPA's 2022 Annual Electricity Procurement Plan.

After the September 30, 2021 comment deadline, the IPA will then have 21 days (as allowed under Section 16-111.5(b)(5)(ii)) to revise its draft Second Revised Plan. That Second Revised Plan will then be filed with the Commission for approval on or before October 21, 2021.

The Commission's approval of the Second Revised Plan will take the form of a docketed proceeding conducted pursuant to the Commission's Rules of Practice.⁷⁰ Within 14 days of the filing of the Revised Plan, parties taking issue with the plan may file an objection with the Commission; assuming the IPA files its Second Revised Plan on October 21, 2021, that objection deadline will be November 4, 2021.⁷¹

The Commission will have 120 days from the IPA's filing to issue a Final Order approving the plan with any modifications.⁷²

2.2.8. Plan Updates

While the Agency's long-term renewable resources procurement plan features a "long-term" focus, many elements informing future program and procurement decisions—technological progress, marketplace changes, the success or failure of work undertaken under a prior-approved approach—were unknowable at the time of the Initial Plan's publishing and are still unknowable as of today.

As described above, the PUA provides that the Agency "shall review, and may revise, the plan at least every 2 years" after the Initial Plan, and "shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency's other planning and approval processes"⁷³ conducted under Section 16-111.5 of the PUA—specifically, the annual procurement plan development and approval process referenced in Section 16-111.5(d). At present, and absent a statutory change through new legislation, the Agency tentatively plans for its next revisions to its Long-Term Renewable Resources Procurement Plan to be proposed in 2023, as part of the development and approval process of the IPA's 2024 annual procurement plan.

⁷⁰ 83 Ill. Adm. Code 200, *et. seg.*

⁷¹ 220 ILCS 5/16-111.5(b)(5)(ii)(C).

⁷² *Id.*

⁷³ 220 ILCS 5/16-111.5(b)(5)(ii)(B).

The PUA also requires that “the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change” on or before July 1 of each year.⁷⁴ This has taken the form of written recommendations, technical or substantive, being submitted to the Commission and posted publicly on the Commission’s website.⁷⁵

2.3. The RPS and Percentage-Based Goals of the RPS

The Illinois RPS shares similarity with other state RPSs which require that a certain percentage of electricity sales be met with a climbing percentage of renewable energy or renewable energy credit procurement. For Illinois, this total is 25% by 2025: “13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter.”⁷⁶

2.3.1. Load Applicable to RPS Goals

At first blush, the Agency’s 25% by 2025 goal appears to mirror the Section 1-75(c)(1) targets found in Illinois law prior to P.A. 99-0906. However, prior to P.A. 99-0906, only “eligible retail customer” load—meaning load associated with utility default supply customers, and not customers taking supply through alternative retail electric suppliers or through hourly pricing—was subject to this requirement. In recent years, only 30-50% of potentially eligible retail customer load actually received default supply service, while competitive class customers (including all medium to large commercial and industrial customers—who represent approximately half of total load) had no default supply option. Stated differently, while the RPS featured a “25% by 2025” requirement prior to P.A. 99-0906, the vast majority of retail customer load in Illinois was not covered by Section 1-75(c)(1)’s “25% by 2025” RPS goal.

Over two delivery years (beginning with the 2017 delivery year), P.A. 99-0906 transitioned those goals applicable only to “eligible retail customer” load to goals applicable to all “all load for retail customers.” For the 2017 delivery year, those goals were “equal to at least 13% of each utility's load for eligible retail customers and 13% of the *applicable portion* of each utility's load for retail customers who are not eligible retail customers,” with the applicable portion at 50%. For the 2018 delivery year, the percentage goal increased to 14.5% while the applicable portion increased to 75%. For the 2019 delivery year, the percentage goal increased to 16% and applied to all retail customer load, including load associated with ARES customers.⁷⁷ The percentage goal continues to increase each year by 1.5% until it reaches 25% in the 2025 delivery year.

One exception exists to this load calculation transition: under Section 1-75(c)(1)(H), if an ARES owned one or more renewable generating facilities that were not wind or photovoltaic as of December 31, 2015, then that ARES may elect “to supply its retail customers with renewable energy credits from the facility or facilities” so long as those facilities continued to be owned by that ARES.

⁷⁴ 220 ILCS 5/16-111.5(b)(5)(vi). Information about the Commission’s most recent informal hearing can be found here: <https://www.icc.illinois.gov/programs/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2021>.

⁷⁵ For example, see: <https://www.icc.illinois.gov/workshops/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2019>.

⁷⁶ 20 ILCS 3855/1-75(c)(1)(B).

⁷⁷ Id.

This self-procurement from ARES-owned facilities by the ARES thus serves to reduce the statutory renewable energy resource obligation by the amount of RECs self-procured.⁷⁸

Further discussion of how these percentage-based multipliers apply to retail customer load to create actual REC procurement targets can be found in Chapter 3. As further discussed within that Chapter, of the renewable energy credits procured under Section 1-75(c), “at least 75% shall come from wind and photovoltaic projects.”⁷⁹

Notably, these requirements only apply to load served by Illinois’ major electric distribution utilities: ComEd, Ameren Illinois, and that portion of MidAmerican load for which the IPA conducts procurements. The Illinois RPS goals do not apply to load served by municipal electric utilities, rural electric cooperatives, or Mt. Carmel Public Utility, and those entities do not have renewable energy procurement obligations under Illinois law.

2.3.2. Eligible Projects for the Illinois RPS

Not all renewable energy generating facilities are eligible to sell RECs into the Illinois RPS. Changes made through P.A. 99-0906 significantly narrowed the universe of facilities capable of generating RECs which qualify for the RPS, and specific criteria applicable to RECs or facilities producing those RECs are discussed further below.

2.3.2.1. Eligible Generating Technologies

The Illinois Power Agency Act’s definition of “renewable energy resource” sets forth the generating technologies capable of producing RECs eligible for the Illinois RPS. As set forth in Section 1-10 of the IPA Act, the underlying energy must be generated “from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams,” as well as “landfill gas produced in the State.” While this language largely mirrors the definition of “renewable energy resource” prior to P.A. 99-0906, that Act deleted the inclusion of “other alternative sources of environmentally preferable energy” from the former definition, thus clarifying that only those generating technologies delineated in the definition may qualify.⁸⁰

The Act also sets forth certain generating technologies categorically incapable of producing RECs eligible for the Illinois RPS, which include “the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.”⁸¹

⁷⁸ For the 2021-2022 delivery year, see the following report on the RECs supplied under this provision: <https://www2.illinois.gov/sites/ipa/Documents/2021-2022%20Delivery%20Year%20ARES%20REC%20Report.pdf>. Tables describing progress toward RPS goals found in Chapter 3 account for these RECs.

⁷⁹ 20 ILCS 3855/1-75(c)(1)(C).

⁸⁰ The Agency understands that hydropower facilities featuring new turbines added to existing non-hydropower dams would not be eligible to participate as these facilities would constitute a newly constructed “hydropower” dam, and would thus be prohibited under Section 1-10 of the IPA Act’s limitation of eligible hydropower only to “hydropower that does not involve new construction or significant expansion of hydropower dams.”

⁸¹ 20 ILCS 3855/1-10.

Please note that these requirements are merely threshold requirements for the Illinois RPS; specific programs, such as the Adjustable Block Program, and specific outlined procurement targets may carry additional limitations.

2.3.2.2. Eligible Projects—Locational

P.A. 99-0906 introduced new locational and public interest benefit requirements for generating facilities seeking to sell RECs into the Illinois RPS. From the introduction of the Illinois RPS in 2007 to June 1, 2011, Section 1-75(c) required the Agency to first look to renewable energy resources from Illinois, then to resources from states adjoining Illinois, and then to elsewhere. After June 1, 2011, until the passage of P.A. 99-0906, the IPA first looked to resources from Illinois and adjoining states, and next to “elsewhere.”

Under the regime introduced by P.A. 99-0906, through Section 1-75(c)(1)(I), a generating facility’s RECs are no longer prioritized based on location; instead, the facility either qualifies for the Illinois RPS, or it does not.

Section 1-75(c)(1)(I) provides that the Plan must be designed “to maximize the State’s interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State.” While the statute determines that a facility located in-state provides those benefits at a sufficient level, the Agency may also “may qualify renewable energy credits from facilities located in states adjacent to Illinois if the generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State’s interest in the health, safety, and welfare of its residents” based on this public interest criteria. As the law provides no discussion of potentially qualifying facilities located in states not “adjacent to Illinois,” facilities located in those states cannot produce RECs for satisfying the Illinois RPS.

The Agency’s discussion of how to apply these criteria to adjacent state facilities, as well as a listing of which states are considered “adjacent” to Illinois, can be found in Chapter 4.

2.3.2.3. Eligible Projects—Cost Recovery

Through Section 1-75(c)(1)(J), RECs from “a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017” are also considered non-compliant with the Illinois RPS. The statute’s stated rationale behind this prohibition is to “promote the competitive development of renewable energy resources in furtherance of the State’s interest in the health, safety, and welfare of its residents.”

In application, the Agency has come to understand that this limitation does not apply to municipal utilities or rural cooperatives that effectively serve as vertically-integrated utilities (as even insofar as they can achieve full cost recovery for the development of renewable energy generating facilities through rates, their rates are in most cases still not regulated by “this state or any other state or states”),⁸² but would still apply to *non-electric* utilities (e.g., water, gas, telecommunications)

regulated by the Illinois Commerce Commission or by another state for which rate recovery could be sought for a photovoltaic system participating in the Illinois RPS.

The law also offers more punitive consequences if a non-regulated rate facility becomes a regulated rate facility after the execution of an Illinois RPS contract. In such a situation, the contract must be terminated and “the supplier of the credits must return 110% of all payments received under the contract”⁸³ (with those payments then being used for the procurement of additional RECs from new wind or photovoltaic generation in the Agency’s next procurement event). Since the passage of P.A. 99-0906, contracts developed for the Agency’s programs and procurements have contained provisions reflecting this penalty.

The Agency’s approach to these issues is discussed in Chapter 4.

2.3.2.4. Installer Requirements

Certain facilities seeking to participate in the RPS are also subject to an installer qualification requirement. Specifically, RECs from “new photovoltaic projects or new distributed renewable energy generation devices [. . .] must be procured from devices installed by a qualified person in compliance with the requirements of Section 16-128A of the Public Utilities Act and any rules or regulations adopted thereunder.”⁸⁴

In Docket No. 17-0268, the Illinois Commerce Commission adopted its Title 83, Part 461 administrative rules for the installation of new utility-scale photovoltaic generating projects under Section 16-128A of the PUA. In that proceeding, the Commission adopted the following definition for the term “qualified person” for new utility-scale solar installations:

*“Qualified person” means a person who performs installations on behalf of the certificate holder and who has completed at least one of the following programs requiring lab or field work and received a certification of satisfactory completion: an apprenticeship as a journeyman electrician from a USDOL-registered or an applicable state-agency-registered electrical apprenticeship and training program; a North American Board of Certified Energy Practitioners (NABCEP) distributed generation technology certification program; an electrical training program for in-house employees established and administered by an electric utility regulated by the Commission; or an Associate in Applied Science degree from an Illinois Community College Board-approved community college program in solar generation technology.*⁸⁵

The Part 461 rules also provide a definition of the term “install”:

“Install” means to perform the electrical wiring and connections necessary to interconnect the new solar project with the electric utility’s transmission or distribution system at the point of interconnection between the project and the utility. “Install” in this Part specifically does not mean:

⁸³ 20 ILCS 3855/1-75(c)(1)(J).

⁸⁴ 20 ILCS 3855/1-75(c)(7). The “qualified person” requirement is expressly not applicable to the Illinois Solar for All Program (see 20 ILCS 3855/1-56(b)(2), final paragraph), although installers of ILSFA projects must, under state law, still have ICC certification under Part 468 as Distributed Generation Installers.

⁸⁵ 83 Ill. Adm. Code § 461.10.

- *Electrical wiring and connections to interconnect the new solar project performed by utility workers;*
- *Electrical wiring and connections internal to the new solar project performed by the manufacturer;*
- *The on-site construction and installation of a solar panel or a collector substation; or*
- *Tasks relating to construction, planning and project management performed by individuals such as an inspector, management planner, consultant, project designer, or contractor for the project or their employees.*

Definitions of these terms were initially approved by the Commission in a Second Notice Order entered on August 25, 2017, and approved with modification by the state’s Joint Committee on Administrative Rules (“JCAR”) on October 24, 2017 with an effective date of October 26, 2017.

Any parties seeking to develop new photovoltaic projects or DG projects in Illinois should also be aware of the Commission’s Part 461 and Part 468 rules (governing distributed generation installers) and certification process more generally as well. The definition of “Qualified person”⁸⁶ may preclude the inclusion of self-installed new photovoltaic projects in the Adjustable Block Program (unless the self-installer meets the “qualified person” definition).

2.3.3. Compliance Mechanism: RECs vs. “Renewable Energy Resources”

One other change to the Illinois RPS through P.A. 99-0906 concerned an added focus on the use of RECs as the compliance mechanism for meeting Illinois renewable energy procurement targets. Prior to P.A. 99-0906, Section 1-75(c) required renewable energy procurement targets to be met through the procurement of “renewable energy resources”—either a REC, or the REC and its underlying energy. While the vast majority of the IPA’s procurement activities focused only on the procurement of RECs, the 2010 long-term power purchase agreements are 20-year contracts for the delivery of a “bundled” REC and energy product.

Rather than using the term “renewable energy resources,” Section 1-75(c)(1)(B) requires that the Plan “shall include the goals for procurement of renewable energy credits”⁸⁷ to meet the statute’s targets. While the description of the ARES load transition later in that same subparagraph (B) uses the term “renewable energy resources,” subparagraph (C) and later subparagraphs also refer only to the procurement of “renewable energy credits” (although subparagraph (E) references “renewable energy resources”).

A shift in focus from “resources” to “RECs” makes intuitive sense; the IPA’s prior Section 1-75(c) renewable energy planning and procurement processes were conducted in conjunction with the development of its annual procurement plan for meeting the energy supply requirements of eligible retail customers, and used to meet procurement requirements specific to that customer base. While the IPA now conducts renewable energy planning and procurement processes to (eventually) meet

⁸⁶ For the definition of “qualified person” under Part 468, please see 83 Ill. Adm. Code § 468.20, <http://www.ilga.gov/commission/jcar/admincode/083/083004680000200R.html>.

⁸⁷ Emphasis added.

goals and targets applicable to all retail customer load,⁸⁸ its energy procurements still focus only on eligible retail customer load—thus creating a disconnect between the universes of supply requirements served by these two exercises.

Since the passage of P.A. 99-0906 and the competitive procurement events that followed, the IPA has become aware of concerns held by developers of utility-scale renewable energy projects that there may be a shallow market for long-term bilateral energy off-take agreements for geographically-qualifying new projects, which developers believe are necessary for providing the revenue certainty required for financing new facility construction. That concern will likely only grow in future years if additional utility-scale REC procurements are authorized, as buyers that may have been able to commit to purchase the generation of the first wave of these projects may no longer have room in their energy portfolios.⁸⁹ While the IPA continues to believe it is an open question as to whether it *could* eventually procure a bundled REC and energy product through the Plan or future revisions to it, or some combination of its concurrent planning and procurement processes, any such proposal carries numerous statutory and policy concerns, including but not limited to the following:

- Syncing developer need for long-term revenue certainty with shorter-term focus of IPA energy procurement planning horizons;
- Inability under law to bind competitive retail suppliers (which serve the majority of the Illinois market), municipal electric utilities, or rural electric co-operatives to purchase energy off-take from specific projects;
- Ensuring cost parity across customer classes (as default supply is procured for residential and small commercial customers);
- Managing fluctuating “eligible retail customer” supply levels due to ongoing customer switching;
- Ensuring that energy procured meets the “lowest total cost over time, taking into account any benefits of price stability” goal reiterated throughout the IPA Act and PUA.

To date, the IPA has not received proposals for the procurement of a bundled product (or for the separate procurement of energy from projects facilitated through IPA REC procurements) that sufficiently address these statutory and policy concerns. Absent statutory changes, the Agency continues not to propose any bundled product procurements as part of this Revised Plan and has no plans to do so in the near-term, but remains open to further proposals and feedback.

2.3.4. RPS Funding and Rate Impact Cap

The procurement of renewable energy credits is limited by an annual procurement budget established through a rate impact cap. Specifically, “the total of renewable energy resources procured under the procurement plan for any single year . . . shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid

⁸⁸ Specifically, the IPA’s long-term renewable resources procurement plan shall include renewable resource procurement for 100% of retail customer load beginning with the delivery year beginning June 1, 2019, after procuring for an increasing portion of retail customer load for the prior two delivery years. See 20 ILCS 3855/1-75(c)(1)(B).

⁸⁹ These concerns were reinforced through comments received in the IPA’s April 2020 utility-scale wind procurement comment process; for those comments, see: <https://www2.illinois.gov/sites/ipa/Pages/wind-comments-2020.aspx>.

for these resources in 2011.”⁹⁰ The greater of these amounts—the 2007 amount per kilowatt-hour (“kWh”), as both amounts are known and, for each utility, it is greater⁹¹—then “shall be applied to the actual amount of kilowatthours of electricity delivered, or applicable portion of such amount [. . .] by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory.” This produces an annual REC procurement budget for the “costs of those resources” in a given year.⁹²

Through the budgets established under the rate impact cap and the associated tariffs for the collection of funds, the applicable electric utility “shall be entitled to recover all of its costs associated with the procurement of renewable energy credits” under the Plan, including “associated reasonable expenses for implementing the procurement programs, including, but not limited to, the costs of administering and evaluating the Adjustable Block program.”⁹³ As a result, annual procurement budgets based only on REC costs would be inaccurate, and some estimate of associated administrative expenses must be included and taken into account.

For a limited period, Section 16-108(k) of the PUA allowed for a given delivery year’s unspent budget amounts to be “rolled over” to be available for later delivery years’ expenditures. Specifically, rather than conducting annual reconciliations of collections and costs, the Commission “shall instead conduct a single review, reconciliation, and true-up associated with renewable energy resources’ collections and costs for the 4-year period beginning June 1, 2017 and ending May 31, 2021, provided that the review, reconciliation, and true-up shall not be initiated until after August 31, 2021.”⁹⁴ Over that four-year period prior to the eventual reconciliation, “the utility shall be permitted to collect and retain funds under this subsection (k) and to purchase renewable energy resources under an approved long-term renewable resources procurement plan using those funds regardless of the delivery year in which the funds were collected during the 4-year period.”

The sunset of this rollover period poses an enormous challenge. Nearly two years were required for the development and approval of the Initial Plan, the development of program requirements and project application processes for each of the ABP and Illinois Solar for All, and the selection of projects in each program’s first phase. As a consequence, two years of RPS budgets were collected with few payments made. Further, payments only commence—and thus expenditures only occur—once a system is built and energized.

As discussed further in Chapter 3, and discussed Plan revisions approved by the Commission’s Order on Reopening in Docket No. 19-0995, COVID-19 has caused considerable delays in the energization timelines of new renewable energy projects participating under the Illinois RPS. Because of these development delays, many systems that successfully applied to the Adjustable Block Program (especially community solar projects) and utility-scale projects which won contracts through competitive procurements will not be energized until sometime during the 2021-22 delivery year,

⁹⁰ 20 ILCS 3855/1-75(c)(1)(E).

⁹¹ The specific cost cap rate for each of the three utilities is shown in Table 3-4 in Chapter 3 of this Revised Plan.

⁹² The exception referenced above in Section 1-75(c)(1)(H) serves to reduce available budgets as well, as “the charges that would otherwise be applicable to the retail customers of the alternative retail electric supplier . . . shall be reduced by the ratio of the quantity of renewable energy credits supplied by the alternative retail electric supplier compared to that supplier’s target renewable energy credit quantity.”

⁹³ 20 ILCS 3855/1-75(c)(6).

⁹⁴ Changes under P.A. 99-0906 also provide that the utility shall not be required to “advance any payment or pay any amounts that exceed the actual amount of revenues collected by the utility” under its Section 16-108(k) RPS rider, and “contracts executed under this Section shall expressly incorporate this limitation.” 20 ILCS 3855/1-75(c)(1)(L)(vii); also see 220 ILCS 5/16-111.5(b)(5)(iv).

with funds collected during the first four years thus not authorized by statute for meeting those post-May 31, 2021 expenses. This situation poses risks to full contract payments for the 2021-22 delivery year and potentially beyond, as described further in Chapter 3.

Without a statutory extension of this rollover period, the Agency anticipates a substantial refund back to ratepayers of collections previously made to fund renewable energy resource procurement. While a reconciliation proceeding for settling the difference between expenditures and collections may not conclude until 2022 (or possibly even 2023), under Riders REA filed by ComEd and Ameren Illinois, the IPA understands that the utilities will perform a calculation to estimate the required adjustment and commence refunds of collections under ComEd's Rider REA on its customers' September bills and under Ameren's Rider REA on its customers' October bills.

Beginning with the 2021-2022 delivery year, annual renewable energy resources expenditures cannot exceed annual RPS rider collections (plus any other funds separately available to meet those expenses), with annual reconciliations of expenditures and collections set to commence under Section 16-108(k) of the PUA. As available funds have become constrained due to the sunsetting of the rollover and RPS budget impacts in the 2021-22 delivery year have unexpectedly increased, reliance on previously-collected alternative compliance payments will be necessary to maximize the degree to which REC delivery contract payment obligations can be met.

Further discussion of the statutory rate impact cap, the delivery year RPS budgets produced under the rate impact cap, the impacts of the above-referenced rollover period sunsetting on June 1, 2021, the balance of alternative compliance payments available to supplement annual RPS budgets, and the IPA's proposed approach for handling reduced payments with expected expenses exceeding available funding can all be found in Chapter 3.

2.3.5. Employment Opportunities

The law also provides that “the renewable energy credit procurements, Adjustable Block solar program, and community renewable generation program shall provide employment opportunities for all segments of the population and workforce, including minority-owned and female-owned business enterprises, and shall not, consistent with State and federal law, discriminate based on race or socioeconomic status.”⁹⁵ The IPA believes strongly in the principles outlined in this statement in the law, and hopes that this Plan—including provisions to lower the barrier to entry in the Adjustable Block Program for minority-owned and female owned businesses, its Illinois Solar for All proposals, its approach to generation in adjacent states, its workforce reporting requirements, and its approach to the geographic diversity of projects within Illinois—will help result in those opportunities being provided. The Agency also understands that substantially more robust statutory directives along these lines are presently being considered by the Illinois General Assembly.

2.4. Quantitative New Build Targets of the RPS

Section 1-75(c)(1)(B) of the IPA Act establishes percentage-based umbrella goals for RECs required to be procured based on a percentage of applicable retail customer load. But within those umbrella requirements, more specific requirements must also be met—and indeed prioritized above meeting those percentage-based goals.

⁹⁵ 20 ILCS 3855/1-75(c)(7).

One such requirement is the procurement of RECs from “new wind projects” and “new photovoltaic projects” found in Section 1-75(c)(1)(C). Rather than expressed as a percentage of load, these requirements are expressed on a quantitative basis (i.e., a statutorily-defined minimum number of RECs required to be delivered annually from these new projects) while still counting toward the overall renewables percentage-based procurement goals.

2.4.1. Quantitative Procurement Requirements

The quantitative targets found in Section 1-75(c)(1)(C) are straightforward and symmetrical, and operate as follows:

By the end of the 2020 delivery year (May 31, 2021):

- At least 2,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 2,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

By the end of the 2025 delivery year (May 31, 2026):

- At least 3,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 3,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

By the end of the 2030 delivery year (May 31, 2031):

- At least 4,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 4,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

For the “new photovoltaic project” requirement, at least 50% must be procured from solar photovoltaic projects using the Adjustable Block Program (used to support distributed generation and community solar, as discussed further below), at least 40% from utility-scale solar projects, and at least 2% from non-community solar brownfield site photovoltaic projects.⁹⁶ The Agency has interpreted this “at least 50%” concept to be first, in terms of RECs (as opposed to budget or installed capacity), and also, of the quantitative target amounts listed in the law (as, in each of Sections 1-

⁹⁶ The IPA Act, as modified by P.A. 99-0906, defines a “brownfield site photovoltaic project” as:

[P]hotovoltaics that are:

(1) interconnected to an electric utility as defined in this Section, a municipal utility as defined in this Section, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act; and

(2) located at a site that is regulated by any of the following entities under the following programs:

(A) the United States Environmental Protection Agency under the federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended;

(B) the United States Environmental Protection Agency under the Corrective Action Program of the federal Resource Conservation and Recovery Act, as amended;

(C) the Illinois Environmental Protection Agency under the Illinois Site Remediation Program; or

(D) the Illinois Environmental Protection Agency under the Illinois Solid Waste Program.

75(c)(1)(C)(i), (ii), and (iii) “of that amount” references the REC amount expressly preceding it in the law), and not necessarily 50% of the overall number of RECs procured.⁹⁷

Significant progress has been made since the development of the IPA’s Initial Plan on meeting these targets, with millions of RECs under contract to be delivered annually from new wind and new photovoltaic projects. Further discussion of this progress can be found in Chapter 3 of this Revised Plan, while the Agency’s discussion of competitive procurements for meeting these targets can be found in Chapter 5.

2.4.2. “New wind project” and “new photovoltaic project” Definition

The definitions of a “new wind project” and a “new photovoltaic project” are also addressed through the statute. What constitutes a “new photovoltaic project” is straightforward; it is a “photovoltaic renewable energy facilit[y] that [is] energized after June 1, 2017.”⁹⁸ Projects developed under Section 1-56 of the IPA Act (i.e., supplemental photovoltaic and Illinois Solar for All projects) are not eligible to meet quantitative “new photovoltaic project” targets.⁹⁹

The definition of a “new wind project” is more awkward. The law defines “new wind projects” as “wind renewable energy facilities that are energized after June 1, 2017 for the delivery year commencing June 1, 2017 or within 3 years after the date the Commission approves contracts for subsequent delivery years.”¹⁰⁰ The IPA understands that “for subsequent delivery years”—projects for which contracts are entered into on or after June 1, 2018—the “3 years after the date” of contract approval is effectively a deadline by when the facility must be “energized” for it to retain its “new” status under the law going forward. Stated differently, if the facility is able to be energized within 3 years after the date on which the Commission approves its REC contract, then those RECs may be counted toward the “new wind project” procurement targets in the law over the life of the contract. However, if the wind project cannot energize within 3 years after Commission approval, its RECs may not be used to count toward quantitative “new wind project” targets, and resultant REC delivery contracts should reflect a consequence for that change in legal status (as the project’s RECs would then have less value in meeting the requirements of the RPS; they would meet the percentage goals of Section 1-75(c)(1)(B) of the Act, but not the quantitative REC targets of Section 1-75(c)(1)(C)).

Both of these definitions raise the question of what constitutes a facility being “energized.” Unlike interconnection, where official approval is required and associated forms are produced and executed on a specific date, “energized” is more nebulous and, unfortunately, not defined through the law. Faced with a similar quandary in developing its Supplemental Photovoltaic Procurement Plan, the Agency settled on a definition of “energized” as being “the date by which the System has been turned on for a period of 24 consecutive hours and is operational for purposes of generating electricity regardless of whether the system has registered with a REC tracking system.” Parties could then

⁹⁷ Thus, if the Adjustable Block Program were to exceed the targets of 1,000,000 RECs delivered annually by the end of 2020-2021 and 1,500,000 RECs by the end of 2025-2026, the “at least 40%” requirement for utility-scale photovoltaic projects remains at 40% of the new photovoltaic targets stated in the law, or 800,000 RECs by the end of the 2020 delivery year and 1,200,000 RECs by the end of the 2025 delivery year. 20 ILCS 3855/1-75(c)(1)(C)(i), (ii). The reverse must likewise be true (supra-target outcomes for utility-scale photovoltaic procurements do not increase ABP targets), as the Commission in Docket No. 17-0838 authorized utility-scale photovoltaic procurements resulting in significantly more utility-scale PV RECs under contract than the Adjustable Block Program could possibly sustain given budget limitations.

⁹⁸ 20 ILCS 3855/1-10.

⁹⁹ Id.

¹⁰⁰ 20 ILCS 3855/1-75(c)(1)(C).

substantiate a system's energization through a certification accompanied by the submission of various forms establishing a system's energization timeline. The Agency notes that unlike the Supplemental Photovoltaic Procurement process, in which payment for RECs was made after REC generation and only upon delivery and invoice to the Agency, the Adjustable Block Program and the Illinois Solar for All Program feature prepayment for some, or all, of the RECs from a system upon energization. Therefore, as discussed in Chapters 6 and 8, consideration is also given to a system being registered in a tracking system to generate RECs in addition to the date on which interconnection to the utility was approved.

2.4.3. Initial Forward Procurements

Independent of (and, in some cases, prior to) the development of the Initial Plan, P.A. 99-0906 required the IPA to conduct "initial forward procurements" of RECs from "from new utility-scale wind projects" and "from new utility-scale solar projects and brownfield site photovoltaic projects."¹⁰¹ Conducted through competitive procurement processes subject to applicable requirements of Section 16-111.5 of the PUA, the Initial Forward Procurement sought 15-year REC delivery contracts set to begin delivery on June 1, 2019 at the earliest and—initially—June 1, 2021 at the latest (that deadline has since been extended to June 1, 2022 through Public Act 101-0113 in the case of certain development risks). For both wind and solar, the targeted overall REC procurement quantities were 1,000,000 RECs delivered annually from each generating technology, with a single wind procurement event required to take place within 160 days of June 1, 2017 and the solar procurement potentially conducted across multiple procurement events up to one year from June 1, 2017.¹⁰²

Section 1-75(c)(1)(G) of the Act provides that RECs procured through the Initial Forward Procurement "shall be included in the Agency's Long-Term Renewable Resources Procurement Plan and shall apply to all renewable energy goals"¹⁰³ found in Section 1-75(c) of the IPA Act, including the quantitative "new wind" and "new photovoltaic" targets discussed above. The Agency's Initial Forward Procurement events for new utility-scale wind and new photovoltaics, conducted in 2017 and 2018, have concluded;¹⁰⁴ the results of the Initial Forward Procurement, and how those results inform remaining quantitative procurement targets, are discussed further in Chapters 3 and 5.

2.4.4. Subsequent Forward Procurements

Section 1-75(c)(1)(G)(iii) also floats the concept of "subsequent forward procurements." That section sets forth conditions applicable to subsequent forward procurements: they must be "for utility-scale wind projects," they "shall solicit at least 1,000,000 renewable energy credits delivered annually per procurement event," and they shall be "planned, scheduled, and designed such that the cumulative amount of [RECs] delivered from all new wind projects in each delivery year shall not exceed the Agency's projection of the cumulative amount of [RECs] that will be delivered from all new photovoltaic projects," in that same delivery year.

The law does not contain statements either requiring that the Agency actually conduct a Subsequent Forward Procurement, or requiring that RECs from utility-scale wind projects may only be procured

¹⁰¹ 20 ILCS 3855/1-75(c)(1)(G)(i), (ii).

¹⁰² *Id.*

¹⁰³ *Id.*

¹⁰⁴ More information about the Initial Forward Procurements can be found at on the IPA Procurement Administrator's website at the following address: <https://www.ipa-energyrfp.com/2017-2018-initial-forward-procurements>.

using a Subsequent Forward Procurement approach. However, in Docket No. 17-0838, the Commission approved two Subsequent Forward Procurements for RECs from new utility-scale wind projects as part of the Initial Plan, intended to allow the Agency to potentially meet the Section 1-75(c)(1)(C)(i) 2020 and 2025 Delivery Year quantitative new wind targets.

RECs under contract from Subsequent Forward Procurements are included in tables found in Chapter 3, while further discussion of competitive procurement events including any proposed Subsequent Forward Procurements can be found in Chapter 5.

2.4.5. Balancing Expected Wind RECs vs. Solar RECs

In addition to the condition placed on subsequent forward procurements mentioned above, the law also contains a more general requirement that RECs under contract from new wind projects not significantly exceed RECs under contract from new photovoltaic projects. Specifically, if the projected amount of RECs from new wind projects to be delivered in a given delivery year exceeds the projected amount of RECs from new photovoltaic projects by 200,000 or more RECs, then “the Agency shall within 60 days adjust the procurement programs in the long-term renewable resources procurement plan to ensure that the projected cumulative amount of renewable energy credits to be delivered from all new wind projects does not exceed the projected cumulative amount of renewable energy credits to be delivered from all new photovoltaic projects by 200,000 or more renewable energy credits.”¹⁰⁵

This requirement is not intended to be applicable to results from the Initial Forward Procurements, at least initially. Given that the Initial Forward Procurement calls for 1,000,000 RECs from “new wind projects” to be procured “within 160 days after the effective date” of P.A. 99-0906, but the Initial Forward Procurement from “new photovoltaic projects” is to be procured “within one year after the effective date,” the law openly accommodates a longer time horizon for bringing solar RECs under contract from the initial forward procurements. As the law expressly establishes this matching requirement as only applicable “at any time after the time set for delivery of renewable energy credits pursuant to the initial procurements,”¹⁰⁶ the Agency understands that this requirement becomes applicable to its planning process after June 1, 2022, the latest date for first delivery of RECs from the initial forward procurements as discussed in Section 2.2.5.2 above.¹⁰⁷

The law also provides that the Agency shall provide “its projection of the renewable energy credits to be delivered from all projects in each delivery year” on a “quarterly basis.”¹⁰⁸ While the IPA will continue to regularly track RECs from new wind projects versus new photovoltaic projects internally, it understands that these quarterly updates would only need to begin being formally provided upon the matching requirement becoming applicable to its planning process. As that requirement will become effective during the time period governed by this Second Revised Plan, the IPA seeks feedback from stakeholders commenting on this Second Revised Plan as to how the Agency can most effectively provide those quarterly projections of REC deliveries to interested parties.

¹⁰⁵ 20 ILCS 3855/1-75(c)(1)(G)(iv).

¹⁰⁶ *Id.*

¹⁰⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

¹⁰⁸ 20 ILCS 3855/1-75(c)(1)(G)(iv).

Further discussion of this requirement, including the current balance of RECs under contract from new wind projects versus new photovoltaic projects, can be found in Chapter 3.

2.5. Adjustable Block & Community Renewable Generation Programs

As referenced above, at least 50% of the quantitative new photovoltaic targets found in Section 1-75(c)(1)(C) of the IPA Act shall be procured “from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy generation devices or community renewable generation projects”—i.e., using the Adjustable Block Program.

2.5.1. Adjustable Block Program

At its core, the Adjustable Block Program is perhaps most notable for what it is not: it is not a “competitive procurement event” using “pay as bid” pricing with selection of bids on the basis of price. Nor is it a project selection process through which public interest criteria, such as those set forth in Section 1-75(c)(1)(I) or those employed for the selection of winning bids under the Zero Emission Standard found in Section 1-75(d-5) of the Act, determine the winning bidder.

Instead, the Adjustable Block Program provides “a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time.”¹⁰⁹ Stated differently, a party seeking a REC contract—such as a photovoltaic distributed generation or community solar project developer—knows the REC price in advance, and should generally have visibility into when and how that price may change. The law sets forth other requirements of the Adjustable Block Program: it must include “a schedule of standard block purchase prices to be offered; a series of steps, with associated nameplate capacity and purchase prices that adjust from step to step; and automatic opening of the next step as soon as the nameplate capacity and available purchase prices for an open step are fully committed or reserved.”¹¹⁰ Thus, each block constitutes a quantity of nameplate capacity with a REC price¹¹¹ attached to that block, and when a block is fully subscribed by qualifying projects, projects may then qualify for the next block (which features a different price). The Agency understands that “automatic opening” as used in the law need not be “immediate” or “instantaneous,” and instead that “automatic” refers to the ability for the block to open in a predictable manner not requiring additional administrative action.¹¹²

2.5.1.1. Adjustable Block Program—Projects

On a broad level, the Adjustable Block Program supports only two project types: photovoltaic distributed renewable energy generation devices (i.e., solar DG), and photovoltaic community renewable generation projects (i.e., community solar¹¹³).

¹⁰⁹ 20 ILCS 3855/1-75(c)(1)(K).

¹¹⁰ *Id.*

¹¹¹ Prices can be a set value, or established as the product of a formula.

¹¹² Through its Final Order in Docket No. 19-0995, the Commission further reinforced this paragraph’s description of what is statutorily required from an “Adjustable Block Program” by finding that a proposal under which block prices would be set through a reverse auction “would require legislative action.” Docket No. 19-0995, Final Order dated February 18, 2020 at 46.

¹¹³ There are other forms of community solar recognized by Illinois law, including (A) properties owned or leased by multiple customers that contribute to the operation of an eligible renewable electrical generating facility, and (B) individual units, apartments, or properties located in a single building that are owned or leased by multiple customers and collectively served by a common eligible renewable electrical generating facility. 220 ILCS 5/16-107.5(l)(1). These forms of community solar are not eligible for the Adjustable Block Program.

Under Illinois law, a photovoltaic distributed renewable energy generation device must be:

- (1) Powered by photovoltaics;
- (2) interconnected at the distribution system level of either an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, or a rural electric cooperative as defined in Section 3-119 of the Public Utilities Act (and thus, must be located in Illinois to be interconnected to such an entity);
- (3) located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and
- (4) limited in nameplate capacity to less than or equal to 2,000 kilowatts.¹¹⁴

Under Illinois law, a photovoltaic community renewable generation project is a generation facility that:

- (1) is powered by photovoltaics;
- (2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act (and thus, must be located in Illinois to be interconnected to such an entity);
- (3) credits the value of electricity generated by the facility to the subscribers of the facility; and
- (4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.¹¹⁵

Only new projects—those “energized on or after June 1, 2017”—are eligible for the Adjustable Block Program.

In terms of what project types participate at what level within the Adjustable Block Program, the law provides the following delineation:

- (1) At least 25% from distributed renewable energy generation devices with a nameplate capacity of no more than 10 kilowatts;
- (2) At least 25% from distributed renewable energy generation devices with a nameplate capacity of more than 10 kilowatts and no more than 2,000 kilowatts.¹¹⁶
- (3) At least 25% from photovoltaic community renewable generation projects.
- (4) The remaining 25% shall be allocated as specified by the Agency in the long-term renewable resources procurement plan.¹¹⁷

Through the Commission’s determination in Docket No. 17-0838 requiring the remaining 25% allocation for the first phase of the Adjustable Block Program (25% of 1,000,000 RECs delivered annually, or of 666 MW of new installed capacity after applying a standard capacity factor) to be later allocated at the Agency’s discretion,¹¹⁸ it is clear that this language does not necessarily require express allocation to one (or a specific combination) of these three categories through this Plan, and

¹¹⁴ 20 ILCS 3855/1-10.

¹¹⁵ *Id.*

¹¹⁶ The Agency may create sub-categories within this category to account for the differences between projects for small commercial customers, large commercial customers, and public or non-profit customers.

¹¹⁷ 20 ILCS 3855/1-75(c)(1)(K).

¹¹⁸ See Docket No. 17-0838, Final Order dated April 3, 2018 at 60; for the IPA’s April 3, 2019 decision allocating discretionary capacity, see: <http://illinoisabp.com/wp-content/uploads/2019/04/Discretionary-Capacity-Rationale-4.3.19.pdf>.

that some or all of the “remaining 25%” could instead be allocated to adjust for ongoing program performance. This issue is discussed further in Chapter 6.

The law also provides that the Adjustable Block Program shall ensure that RECs are procured from “projects in diverse locations and are not concentrated in a few geographic areas.” The Agency has spent time reviewing the geographic distribution of projects supported thus far through the Adjustable Block Program, and has found that the Program generally features very strong geographic diversity. Some exceptions certainly exist – for instance, while community solar projects facilitated through the program look well-dispersed on a map of the state, development has almost exclusively occurred in less populated rural areas featuring lower land cost – but the IPA has generally been pleased with the degree to which the tens of thousands of projects supported to date through the Adjustable Block Program more broadly demonstrate geographic diversity.

Moving forward, the Agency commits to continue to monitor the locations of proposed and completed projects. The Agency also now publishes a map on its Adjustable Block Program website providing a visual display of project location by zip code.¹¹⁹ Further discussion of the geographic diversity of Adjustable Block Program projects is found in Chapter 6.

2.5.1.2. Adjustable Block Program—Contracts

Section 1-75(c)(1)(L) sets forth certain requirements applicable to REC delivery contracts entered into through the Adjustable Block Program. The first is that contracts must be “at least 15 years in length,” i.e., for at least 15 years of REC deliveries under the contract. Payment for RECs is made by (and RECs are delivered to) the applicable electric utility (which is then required to retire the RECs), and payment is required by law to occur according to the following schedule:

For DG systems of no more than 10 kW, “the renewable energy credit purchase price shall be paid in full by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized.”¹²⁰ The Agency understands “purchase price” to refer to the sum of payments for RECs required to be made under the contract—i.e. full prepayment.¹²¹

For larger DG systems and community solar projects, “20 percent of the renewable energy credit purchase price shall be paid by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized” with the remaining portion “paid ratably over the subsequent 4-year period.”¹²²

Prepayment poses unique challenges. While RECs are required to be delivered when generated to meet annual utility compliance obligations, prepayment reduces the incentive to actually deliver RECs. On this point, the law requires that each contract “shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract.”

¹¹⁹ See: <https://illinoisabp.com/project-map/>.

¹²⁰ 20 ILCS 3855/1-75(c)(1)(L)(ii). The Agency understands this provision to mean that a system of exactly 10 kW in size would be included in this category.

¹²¹ All prepayment remains subject to the amounts actually collected by the utilities under its Section 16-108(k) tariffs, however, and other available funds (such as alternative compliance payments). (See Section 1-75(c)(1)(L)(vii)).

¹²² 20 ILCS 3855/1-75(c)(1)(L)(iii).

The Revised Plan’s proposed approach to Adjustable Block Program contracts generally, as well as to the clawback provisions, collateral requirements, and other contract elements intended to ensure REC delivery, can be found in Chapter 6.

2.5.1.3. Adjustable Block Program—Changes

Unlike a competitive procurement process, through which changes in market conditions may be reflected in bidders’ bids, the Adjustable Block Program requires that the Agency project future market conditions through establishing future block sizes and prices.

The law envisions these changes occurring in two ways: first, the Agency “may periodically review its prior decisions establishing the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values” subject to the Section 16-111.5 plan revision process.¹²³

Second, “[p]rogram modifications to any price, capacity block, or other program element that do not deviate from the Commission’s approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval.”¹²⁴ To prevent the requirement that the Agency seek formal administrative approval for large modifications from being effectively ignored, the Agency believes this threshold should be understood as a 25% change based on the last formally approved (i.e., through establishment or revision of the Plan via Commission’s Section 16-111.5 approval process) level.

For the Initial Plan, the Commission determined that “the final REC prices the IPA will publish should be filed within 60 days as a compliance filing” in Docket No. 17-0838.¹²⁵ Accordingly, the Agency published its REC prices for the Adjustable Block Program as a compliance filing in Docket No. 17-0838 on June 4, 2018 and these prices served as the baseline for any subsequent modifications of up to 25%.¹²⁶

For this Second Revised Plan, the Agency has provided a preliminary analysis of updated REC prices based upon updating certain inputs into the model used for REC Pricing. The Agency welcomes stakeholder feedback on these input updates, the underlying analysis, and the resultant REC prices.

Section 1-75(c)(1)(M) of the Act requires that the Agency “consider stakeholder feedback when making adjustments to the Adjustable Block design” and “notify stakeholders in advance of any planned change.” Likewise, the law requires that “[t]he Agency and its consultant or consultants shall monitor block activity, share program activity with stakeholders and conduct regularly scheduled meetings to discuss program activity and market conditions.” In implementing the program, the Agency has to date attempted to seek stakeholder feedback for the development of key program requirements or new forms and documents; such documents are published on the program website (www.illinoisabp.com) and new requirements generally become reflected in the Adjustable Block

¹²³ 20 ILCS 3855/1-75(c)(1)(K).

¹²⁴ 20 ILCS 3855/1-75(c)(1)(M).

¹²⁵ Docket No. 17-0838, Final Order dated April 3, 2018 at 73-74.

¹²⁶ See id.

Program Guidebook.¹²⁷ The program website also features a program dashboard updated daily to provide stakeholders with daily updates on block activity,¹²⁸ project information spreadsheets to provide increased transparency about photovoltaic projects supported through the Adjustable Block Program,¹²⁹ and a map of projects supported through the program to date.¹³⁰ In preparing this Second Revised Plan, in addition to the comment process and public hearings required by law, the Agency held both virtual workshops and a written comment process across the summer of 2021 through which comments on program activity and market conditions were offered by stakeholders.¹³¹

As described further in Chapter 6, the Agency will continue to monitor program performance closely and shall seek to be proactive in communicating with stakeholders about program performance and making any necessary changes to the structure of the Adjustable Block Program. The Agency is interested in feedback, through comments on this Draft Second Revised Plan, on how it can more effectively provide regular updates to stakeholders.

2.5.2. Community Renewable Generation Program

P.A. 99-0906 also requires the establishment of a “community renewable generation program.”¹³² Unlike with the Adjustable Block Program, the law does not set forth procurement targets or a proposed contract structure for this program; the Agency thus has latitude to design its Community Renewable Generation Program in any manner otherwise consistent with state law and done “with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties.”¹³³

The statutorily-envisioned interaction between the Agency’s Community Renewable Generation Program, and the portion of the Agency’s Adjustable Block Program set-aside for community solar, is unclear; the law simply references that “subscribed shares of photovoltaic community renewable generation projects” shall be purchased through the Adjustable Block Program.¹³⁴ Thus, the IPA understands the community solar portion of its Adjustable Block Program to be something of a subset of its Community Renewable Generation Program, with a standalone Community Renewable Generation Program required to be established to provide support for community renewable generation projects using technology other than photovoltaics.

2.5.2.1. Portability and Transferability of Subscriptions

Section 1-75(c)(1)(N) requires that “subscriptions” to community renewable generation projects under the Community Renewable Generation Program must be portable (i.e., retained by the

¹²⁷ Both the presently effective Guidebook and prior editions of the Guidebook can be found here: <http://illinoisabp.com/program-guidebook>.

¹²⁸ The Adjustable Block Program dashboard can be found here: <https://illinoisabp.com/block-capacity-dashboard-2/>.

¹²⁹ Project application disclosure information can be found here: <http://illinoisabp.com/project-information-disclosure-process>.

¹³⁰ The ABP project map can be found here: <https://illinoisabp.com/project-map/>.

¹³¹ Information about the IPA’s workshops, as well its request for comments and comments received, can be found here: <https://www2.illinois.gov/sites/ipa/Pages/RenewableResourcesWorkshops.aspx>.

¹³² 20 ILCS 3855/1-75(c)(1)(N).

¹³³ Id.

¹³⁴ Id.

subscriber even if the subscriber relocates or changes its address within the same utility service territory) and transferable (i.e., a subscriber may assign or sell subscriptions to another person within the same utility service territory). These requirements apply to subscriptions for community solar projects participating in the Adjustable Block Program as well.

During the implementation of the Adjustable Block Program, some entities have raised questions regarding the scope of the portability and transferability of community solar subscriptions. It seems clear that the law did not envision completely unconditional portability or transferability: if a resident holding a community solar subscription were to move from a large house to a small apartment, the resultant drop in energy consumption may necessitate downsizing of the community solar subscription. Likewise, there may be numerous reasons why a transferee may be an unworkable recipient of an existing subscriber's community solar subscription, from being legally ineligible (outside of that utility's service territory) to posing a more significant non-payment risk than the transferor. At the same time, allowing unbounded Approved Vendor-imposed restrictions on portability or transferability could easily defeat the spirit of the law's requirement that subscriptions be portable and transferable.

As most community solar projects participating in the Adjustable Block Program are not yet energized (as of August 2021), the Agency has limited experience to date with initial subscriptions to projects—let alone tests of the contours of their portability or transferability. As additional projects energize and begin to cycle through subscribers, the Agency hopes to learn more about what considerations should inform the parameters of portability and transferability requirements.

2.5.2.2. Opt-Out Municipal Aggregation

Certain stakeholders have raised the question of whether community renewable generation project subscriptions (specifically, community solar subscriptions) may be eligible for execution via opt-out municipal aggregation authorized under Section 1-92 of the IPA Act. Under opt-out municipal aggregation, municipalities (after passing authorizing referenda) may aggregate their residential and small commercial customer load and contract with an alternative retail electric supplier to supply those customers with “energy and related services” at a negotiated supply rate unless that customer expressly chooses to “opt-out” of the transaction.

For the IPA, in its role as the entity charged with administering the Adjustable Block Program, Community Renewable Generation Program, and Illinois Solar for Program, this raises, at minimum, two questions:

First, is the enrollment of a customer into a subscription for a community solar project without their direct authorization or consent (i.e., on an “opt-out” basis) legally authorized by Section 1-92 of the IPA Act's governmental aggregation provisions?

Second, even if legally authorized, would that relieve Approved Vendors from program-related responsibilities with respect to individual subscribers, including the requirement that each customer complete a disclosure form acknowledging participation in the program?

As to the first question, the IPA is highly skeptical that opt-out municipal aggregation could legally cover community solar subscriptions, which were not contemplated anywhere in Illinois law when Section 1-92 was enacted via Public Act 96-0176 in 2009 (and notes that countless implementation

issues would be raised under such an approach).¹³⁵ However, only the second of these questions falls within the scope of this Plan. On that question, the Agency’s disclosure form requirements found in Chapter 6 are fundamental to subscribers receiving standardized information. Those requirements constitute the backbone of the Agency’s efforts to deliver uniform content about the rights and obligations under a ratepayer-funded program to everyday citizens. That standardized information and express acknowledgment by a subscriber is an essential form of education that must be provided to each individual participant to produce a transparent, positive experience through its programs. Thus, even if some colorable argument could be made that community solar subscribers could be enrolled without each individual subscriber having offered its direct consent to a given subscription, the Agency would not allow for its program-specific consumer protection requirements—including its standardized brochure and the receipt and execution of a disclosure form—to be waived.

In Docket No. 19-0995, the Illinois Commerce Commission agreed, determining that any community solar subscription aggregation program (if legally possible) for a project participating in the ABP or ILSFA would be required to ensure that every individual subscriber receives and executes an individualized standard disclosure form, pursuant to Section 6.13 of this Revised Plan.¹³⁶ The Commission likewise agreed with the Agency that the question of whether opt-out municipal aggregation for community solar subscriptions is legally authorized under Section 1-92 of the IPA Act is an issue outside the scope of Plan approval, finding that “this proceeding is not the forum for the Commission to decide the legality of opt-out municipal aggregation for community solar subscriptions, as numerous interested stakeholders - such as the many municipalities that might be interested and the private brokers that might assist them in soliciting bids - would not be on notice that the issue is being decided.”¹³⁷

Further discussion of the IPA’s Community Renewable Generation Program can be found in Chapter 7.

2.6. Illinois Solar for All Program

As described in Section 1-56(b) of the IPA Act, the Illinois Solar for All Program shall “include incentives for low-income distributed generation and community solar projects, and other associated approved expenditures” in order “to bring photovoltaics to low-income communities in this State in a manner that maximizes the development of new photovoltaic generating facilities, to create a long-term, low-income solar marketplace throughout this State, to integrate, through interaction with stakeholders, with existing energy efficiency initiatives, and to minimize administrative costs.” Further, the program shall be “designed to grow the low-income solar market.”¹³⁸

A statutory overview of the Illinois Solar for All Program (which began accepting project applications on May 15, 2019), as well as the individual sub-programs under the Illinois Solar for All banner, is below.

¹³⁵ Any community renewable generation project that does not participate in an IPA-administered program or procurement may freely operate outside of this Revised Plan’s requirements. However, given the Agency’s express statutory role (separate from its role administering renewable resources programs under this Plan) assisting governmental aggregation programs under Section 1-92(g) of the Act, the Agency’s perspective should at least carry valuable advisory authority.

¹³⁶ Docket No. 19-0995, Final Order dated Feb. 18, 2020 at 7.

¹³⁷ *Id.*

¹³⁸ 20 ILCS 3855/1-56(b)(2).

2.6.1. Illinois Solar for All—Overview

At its core, the Illinois Solar for All Program is an incentive program—through more generous REC contracts, the Illinois Solar for All Program incents low-income (as well as non-profit and public facility) participation in solar photovoltaic projects, whether as a system owner, community solar project subscriber, or system host. Those RECs are retired (either by the Agency or a utility, depending on which entity was the REC contract counterparty) to satisfy Section 1-75(c) compliance obligations just as with the other procurements and programs described above, while the additional premium helps produce benefits specific to growing the low-income solar marketplace and ensuring more equitable access to the benefits of clean energy. Thus, structurally, the law envisions the Solar for All Program’s incentive being offered through contracts for the delivery of RECs at a premium price above what would otherwise be available, reflecting the additional incentive necessary to ensure low-income participation, with the Agency also having the ability to offer full contract prepayment or otherwise relax (or enhance) requirements in recognition of the unique challenges facing low-income project development.

While the program features no hard targets or goals for the quantity of RECs required to be procured, it does feature defined funding sources. First, Illinois Solar for All is funded through the Renewable Energy Resources Fund. At the time of publishing this draft Plan, the current balance of the RERF is presently just over \$8 million, with an additional \$132.5 million remaining transferred to the state’s General Revenue Fund (\$122.5 million) and Health Insurance Reserve Fund (\$10 million) for liquidity purposes. The IPA considers any contractual obligations from the RERF pre-dating Illinois Solar for All (specifically, Supplemental Photovoltaic Procurement contracts) to be senior to any new obligations entered into through the Illinois Solar for All Program,¹³⁹ and approximately \$5.9 million in such prior obligations remain outstanding.¹⁴⁰ State law requires that the remaining \$132.5 million be transferred back into the RERF within 60 months of its transfer¹⁴¹ (\$112.5 remaining from the August 2017 transfer, \$10 million from the January 2020 transfer, and \$10 million from the March 2020 transfer), but no additional alternative compliance payments are due to be made into the RERF.¹⁴²

Second, Illinois Solar for All is funded through a portion of funds collected by the utilities under their Section 16-108(k) RPS tariffs for purchases made under Section 1-75(c) of the IPA Act. Under Section 1-75(c)(1)(O), “5% of the funds available under the plan for the applicable delivery year, or \$10,000,000 per delivery year, whichever is greater” is available for Illinois Solar for All annually in most years; while “for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or \$20,000,000 per delivery year, whichever is greater” with

¹³⁹ This appears to be the intent evident in Section 1-56(b) as well, as that section prefaces the percentage-based allocation of RERF funds with the qualifier “monies available in the Illinois Power Agency Renewable Energy Resources Fund and not otherwise committed to contracts executed under subsection (j) of this Section.” (emphasis added)

¹⁴⁰ Supplemental Photovoltaic Procurement contracts were for the delivery of RECs for 5 years, with payment for RECs made upon delivery; the procurement’s original budget was \$30 million.

¹⁴¹ 30 ILCS 105/5h.5(b).

¹⁴² Section 16-115D of the PUA provides that while “[t]hrough May 31, 2017, all alternative compliance payments by alternative retail electric suppliers shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund,” “beginning with the delivery year commencing June 1, 2017, all alternative compliance payments by alternative retail electric suppliers shall be remitted to the applicable electric utility” and not deposited into the RERF. (220 ILCS 5/16-115D(d)(4), (4.5).) See also 83 Ill. Adm. Code Part 455. Additionally, with the consolidation of the RPS budgeting and funding mechanisms instituted under P.A. 99-0906, alternative compliance payments by alternative retail electric suppliers ceased being made to any party as of 2019.

\$10 million in each of those three delivery years going toward funding ComEd's workforce development plan. This mechanism ensures a base level of Illinois Solar for All funding annually, which is crucial given the uncertainty surrounding the RERF.

Third, Section 16-108(k) of the PUA contains the following provision:

If the amount of funds collected during the delivery year commencing June 1, 2017, exceeds the costs incurred during that delivery year, then up to half of this excess amount, as calculated on June 1, 2018, may be used to fund the programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act in the same proportion the programs are funded under that subsection (b). However, any amount identified under this subsection (k) to fund programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act shall be reduced if it exceeds the funding shortfall. For purposes of this Section, "funding shortfall" means the difference between \$200,000,000 and the amount appropriated by the General Assembly to the Illinois Power Agency Renewable Energy Resources Fund during the period that commences on the effective date of this amendatory act of the 99th General Assembly and ends on August 1, 2018.

Similar provisions exist in Section 16-108(k) for each of the delivery years commencing June 1, 2018 and June 1, 2019, meaning that there is no single "amount appropriated by the General Assembly to the Illinois Power Agency Renewable Energy Resources Fund" for the 14 months referenced in the paragraph above; instead, there are three separate fiscal year appropriations¹⁴³ covered by this period. Section 16-108(k) provides that should funding for Illinois Solar for All be available under this mechanism, then "the Agency shall submit a procurement plan to the Commission no later than September 1, 2018, that proposes how the Agency will procure programs on behalf of the applicable utility."¹⁴⁴

The IPA filed its Illinois Solar for All Supplemental Funding Plan for approval with the Illinois Commerce Commission on August 30, 2018. That Plan concluded as follows regarding whether to use any unspent RPS rider collections to provide additional funding for the Illinois Solar for All Program:

Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA's annual RRB allocation, the legally-required availability of RERF funds previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)'s requirement that the RERF "shall not be subject to sweeps, administrative charges, or chargebacks," and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.¹⁴⁵

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457, entering its Final Order on October 25, 2018. The Supplemental Funding Plan did note, however, that the Agency

¹⁴³ These are the appropriations for Fiscal Year 2017 (July 1, 2016 through June 30, 2017), Fiscal Year 2018 (July 1, 2017 through June 30, 2018), and Fiscal Year 2019 (July 1, 2018 through June 30, 2019).

¹⁴⁴ 20 ILCS 3855/1-56(b)(7). Perhaps notably, while the requirement that the IPA submit a Plan is prescriptive, Section 16-108(k)'s funding allocation language is merely "permissive" ("up to half this excess amount . . . **may** be used to fund the programs"). The IPA thus did not need to propose, nor did the Commission need to approve, a full (or any) statutorily authorized allocation.

¹⁴⁵ Docket No. 18-1457, Final Illinois Solar for All Funding Shortfall Plan, dated November 26, 2018, at 30.

would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF's balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.¹⁴⁶ Since that time, the opposite situation has occurred, as RERF funding remains a viable source of funding for the program and changes in state law authorizing RERF borrowing maintain payback mandates. However, the sufficiency of utility RPS collections stands threatened by expenses exceeding collections for the 2021-22 delivery year as hundreds of millions of dollars of prior-made collections appear subject to a Fall 2021 refund.

Under the Illinois Solar for All Program, payments “shall be in exchange for an assignment of all renewable energy credits generated by the system during the first 15 years of operation and shall be structured to overcome barriers to participation in the solar market by the low-income community.”¹⁴⁷ The contract “may pay for such renewable energy credits through an upfront payment per installed kilowatt of nameplate capacity paid once the device is interconnected at the distribution system level of the utility and is energized,” giving the Agency flexibility in proposing contract structures.¹⁴⁸

The counterparty to Illinois Solar for All contracts entered into using RERF funds is the Agency, while the counterparty to contracts entered into using utility funds is the applicable utility.

While the Act does not require any particular annual budgetary allocation to ILSFA, the Agency continues to propose to allocate funds and consider project applications within ILSFA based on “program years,” which track the same period of time as energy delivery years (June 1st of one year to May 31st of the following year). The Agency’s proposed budget allocations by program year are described in detail in Chapter 8.

In addition to payments for REC delivery contracts, the law provides that “[t]he Agency shall ensure collaboration with community agencies, and allocate up to 5% of the funds available under the Illinois Solar for All Program to community-based groups to assist in grassroots education efforts related to the Illinois Solar for All Program.”¹⁴⁹ Notably, for grassroots education efforts, this amount is not based only on the balance of the RERF; it is instead “up to 5% of the funds available under the Illinois Solar for All Program,” and thus also inclusive of any Section 1-75(c) or 16-108(k) funds. In implementation, the Agency decided to award grassroots education contracts through a competitive RFP process, with those entities serving as subcontractors to the Agency’s Illinois Solar for All Program Administrator and performing grassroots education activities under that master contract.¹⁵⁰

In addition to grassroots education, “costs associated with procuring experts, consultants, and the program administrator . . . and related incremental costs, and costs related to the evaluation of the Illinois Solar for All Program” may be paid out of the RERF.¹⁵¹

¹⁴⁶ See *id.* at 31.

¹⁴⁷ 20 ILCS 3855/1-56(b)(3).

¹⁴⁸ *Id.*

¹⁴⁹ *Id.*

¹⁵⁰ More information on the Illinois Solar for All grassroots education process can be found here: <https://www.illinoissfa.com/grassroots-education> and in Section 8.15.5.

¹⁵¹ 20 ILCS 3855/1-56(b)(3).

2.6.2. Illinois Solar for All—Sub-programs

Illinois Solar for All is designed to incent specific defined project types, and to this end, Illinois Solar for All features four sub-programs with percentage-based Fund balance allocations applicable to each. Notably, and as described further in Chapter 8, the Agency understands these percentage-based allocations to be applicable only to RERF funds, and not to funds collected by the utilities but available for Illinois Solar for All use (as the law uses the phrasing “monies available in the Illinois Power Agency Renewable Energy Resources Fund”¹⁵² in making those percentage-based assignments).

For the first three sub-programs, these allocations may be changed if, after stakeholder input through a stakeholder process, the Agency or its administrator determines that incentives for any those three sub-programs “have not been adequately subscribed to fully utilize the Illinois Power Agency Renewable Energy Resources Fund.”¹⁵³ As explained further in Chapter 8, there have been varying levels of initial participation across the three sub-programs; however, the Agency believes that given that Illinois Solar for All opened for project applications only months ago, any such reallocation of funding would be premature.

The first three sub-programs also contain “a goal . . . that a minimum of 25% of the incentives for this program be allocated to community photovoltaic projects in environmental justice communities.”¹⁵⁴ The Agency’s definition offered to the term “environmental justice community” is discussed further in Chapter 8 and, at present, is described more comprehensively on the Illinois Solar for All website, which allows for users to search qualification status by address.¹⁵⁵

Discussion of the four sub-programs is below. In addition to these four sub-programs, “a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed” and that additional program or modification will be approved “if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed.”¹⁵⁶

2.6.2.1. Low-Income Distributed Generation Incentive

The Low-Income Distributed Generation Incentive sub-program “provide[s] incentives to low-income customers, either directly or through solar providers, to increase the participation of low-income households in photovoltaic on-site distributed generation.”¹⁵⁷ Used for this sub-program and others, the term “solar provider” has no definition in the statute; to allow the market to determine appropriate models, the Agency has determined that “solar providers” can refer to any entity which

¹⁵² 20 ILCS 3855/1-56(b)(2).

¹⁵³ *Id.*

¹⁵⁴ 20 ILCS 3855/1-56(b)(2)(A), (B), (C).

¹⁵⁵ See: <https://www.illinoisfa.com/environmental-justice-communities>.

¹⁵⁶ 20 ILCS 3855/1-56(b)(4). While an additional program (focused on multi-family properties) was proposed by Elevate Energy and GRID Alternatives in Docket No. 17-0838, that proposal was not adopted by the Commission; instead, the Commission suggested that the IPA “monitor the treatment of multi-family buildings under the Low-Income Distributed Generation Incentive sub-program” and “include the results of that monitoring for the Commission and explain its decision regarding whether to propose a program for this market segment” as part of its 2019 Plan revision filing. Docket No. 17-0838, Final Order dated April 3, 2018 at 153. No additional programs were proposed in Docket No. 19-0995.

¹⁵⁷ 20 ILCS 3855/1-56(b)(2)(A).

has a contractual relationship with the low-income customer in connection with the underlying photovoltaic system (whether in the form of purchase, leasing, installation, aggregation, or financing).

This program contains a firm, unequivocal commitment to using job trainees; the law provides that “companies participating in this program that install solar panels shall commit to hiring job trainees for a portion of their low-income installations,”¹⁵⁸ although the term “portion” is undefined in the law. Nevertheless, the IPA believes that “portion” should not be understood as too small to be de minimis, nor too large to be a “majority” (a term which likely would have been used had it been intended), and its determination for the required level of job trainee participation is discussed further in Chapter 8.

For this sub-program, the law also requires that “an administrator shall facilitate partnering the companies that install solar panels with entities that provide solar panel installation job training.”¹⁵⁹ The IPA understands this to mean its third-party Program Administrator engaging in such facilitation, and this is presently part of the ILSFA Program Administrator’s scope of work.

The law also includes a provision that “[c]ontracts entered into under this paragraph may be entered into with an entity that will develop and administer the program.”¹⁶⁰ It is unclear how the administrator could leverage state funds for this use, and at present, all such contracts will be entered into between Approved Vendors (Sellers) and the State of Illinois or a participating utility (Buyers).

This sub-program is allocated 22.5% of available RERF funds.

2.6.2.2. Low-Income Community Solar Project Initiative

Through the low-income community solar project initiative, “[i]ncentives shall be offered to low-income customers, either directly or through developers, to increase the participation of low-income subscribers of community solar projects.”¹⁶¹ Again, the term “developer” is undefined in the law. As community solar project subscriptions may be actively marketed by entities other than the literal definition of photovoltaic project “developers,” no guidance is provided as to whether this phrasing is intended to include all entities marketing such subscriptions or only the project’s actual developer. The Agency has interpreted “developer” to be an Approved Vendor or their project partner.

A requirement of this program is that each participating project’s developer “shall identify its partnership with community stakeholders regarding the location, development, and participation in the project.”¹⁶² Undefined in this phrasing is what constitutes a “community stakeholder,” or whether the project itself must include “community stakeholders” from the community in which the project is located (presumably so), the community of any subscribers (unclear), or both (also unclear).

The law further provides that “[i]ncentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit

¹⁵⁸ Id.

¹⁵⁹ Id.

¹⁶⁰ Id.

¹⁶¹ 20 ILCS 3855/1-56(b)(2)(B).

¹⁶² Id.

organizations, and affordable housing owners.”¹⁶³ This phrasing leaves program eligibility unclear—must all subscribers be “low-income” for eligibility, or—as the law uses the term “also” in designating 100% low-income projects for eligibility—only a portion (and if so, what portion)? Not all subscriptions are “ownership”; does ownership matter, and should it result in a heightened incentive? These questions have no obvious answer from the law, but the Agency’s approaches are discussed further in Chapter 8.

The law also provides that “[c]ontracts entered into under this paragraph may be entered into with developers,”¹⁶⁴ which the IPA has interpreted to mean that a project developer, upon a sufficient showing of low-income participation, may qualify for a contract award.

This sub-program is allocated 37.5% of available RERF funds.

2.6.2.3. Incentives for Non-profits and Public Facilities

The third sub-program provides that funding “shall be used to support on-site photovoltaic distributed renewable energy generation devices to serve the load associated with not-for-profit customers and to support photovoltaic distributed renewable energy generation that uses photovoltaic technology to serve the load associated with public sector customers taking service at public buildings.”¹⁶⁵ Stated differently, the program operates similarly to the first sub-program—an incentive for on-site DG through a higher-priced REC contract—only with different eligibility requirements (not-for-profit customers and public sector customers taking service at public buildings).

This limited statutory guidance raises the question of whether all non-profits and all public sector entities may qualify for the sub-program, or whether some nexus with the broader “low-income” intent of Illinois Solar for All is required. As discussed further in Chapter 8, the IPA believes that some level of community involvement may be required to maintain consistency with the spirit of the law.¹⁶⁶

This sub-program also combines referenced elements of each of the prior programs, stating that “[c]ontracts may be entered into with an entity that will develop and administer the program or with developers,”¹⁶⁷ which carries similar challenges to those referenced above.

This sub-program is allocated 15% of available RERF funds.

2.6.2.4. Low-Income Community Solar Pilot Projects

The fourth sub-program allows that “persons, including, but not limited to, electric utilities, shall propose pilot community solar projects.”¹⁶⁸ Such projects are allowed by law to be larger than 2 megawatts (“MW”), but “the amount paid per project under this program may not exceed

¹⁶³ Id.

¹⁶⁴ Id.

¹⁶⁵ 20 ILCS 3855/1-56(b)(2)(C).

¹⁶⁶ More information on what is presently required from qualifying non-profits and public facilities can be found here: <https://www.illinoisfa.com/programs/nonprofit-organizations-and-public-agencies>.

¹⁶⁷ Id.

¹⁶⁸ 20 ILCS 3855/1-56(b)(2)(D).

\$20,000,000.”¹⁶⁹ Such projects “must result in economic benefits for the members of the community in which the project will be located” and “must include a partnership with at least one community-based organization” (with that term again undefined).¹⁷⁰

Beyond the allowance that the project may be proposed by an electric utility and may be larger than the law otherwise allows, it is not clear what other requirements make such facilities sufficiently distinct so as to be considered a “pilot project.” While it may be tempting to require demonstration of innovation through this program, at present, the IPA does not believe that any additional limitations or conditions on such projects should be inferred.

While the manner through which contracts are entered into in the other sub-programs is not established in the statute, the low-income community solar pilot project sub-program must be “competitively bid by the Agency,” which the Agency understands to be conducted consistent with the procurement requirements of Section 16-111.5 of the PUA where applicable.

The law further provides that funding under this sub-program “may not be distributed solely to a utility,” and that some funds “must include a project partnership that includes community ownership by the project subscribers.” The IPA thus understands that, for bid selection purposes, disbursement to an entity other than a utility is a prerequisite for a utility bid to win, while satisfying the referenced partnership through a winning bid is a prerequisite for any other bid to win.

As with the other sub-programs, the law again provides that contracts under the Low-Income Community Solar Pilot Project program “may be entered into with an entity that will develop and administer the program or with developers.”¹⁷¹

This sub-program is allocated 25% of available RERF funds.

2.6.3. Illinois Solar for All—Additional Requirements

Section 1-56(b) also provides that, under Illinois Solar for All, “[e]ach contract that provides for the installation of solar facilities shall provide that the solar facilities will produce energy and economic benefits, at a level determined by the Agency to be reasonable, for the participating low income customer.”¹⁷² The Agency believes that this requirement is in part met through the premium attached to the REC price under Illinois Solar for All (and “energy benefits” for community solar and distributed generation projects are already handled through bill crediting and net metering provisions over which the Agency lacks jurisdiction), and provides support for consumer protections to ensure that low income customers indeed receive benefits in entering into contractual arrangements with installers, project developers, aggregators, or other intermediaries. Those specific requirements are discussed in more detail in Section 6.13 and Chapter 8.

Illinois Solar for All contracts must also “ensure the wholesale market value of the energy is credited to participating low-income customers or organizations,”¹⁷³ which, again, is an issue handled through net metering, but can be emphasized in resulting contracts. Contracts must also ensure that “tangible economic benefits flow directly to program participants, except in the case of low-income multi-

¹⁶⁹ Id.

¹⁷⁰ Id.

¹⁷¹ 20 ILCS 3855/1-56(b)(2)(D).

¹⁷² 20 ILCS 3855/1-56(b)(2).

¹⁷³ Id.

family housing where the low-income customer does not directly pay for energy;¹⁷⁴ while it is unclear from the law what constitutes a “tangible economic benefit” (or, for that matter, a “program participant,” especially if the underlying contract is with a project developer or other such entity), the Agency will continue to require, consistent with the Commission Order approving the Initial Plan,¹⁷⁵ that ongoing annualized payments by the customer (if any) must be less than 50% of the annual first year estimated production and/or utility default service net metering value to be received by the customer. Additionally, this language appears to provide further support for ensuring that marketing practices are standardized such that low-income customers receive clear, standardized information about the benefits to be expected from an Illinois Solar for All project.

The law also seeks for priority to be given to projects that “demonstrate meaningful involvement of low-income community members in designing the initial proposal.”¹⁷⁶ Here again, the law provides no definition of “meaningful involvement” nor does it define a “low-income community member,” and it is unclear whether this would be distinct from an “environmental justice community” or what constitutes a community “member.” The law further provides that “[a]cceptable proposals to implement projects must demonstrate the applicant’s ability to conduct initial community outreach, education, and recruitment of low-income participants in the community;” again, the term “participants in the community” is undefined and entirely unclear, but the Agency does understand this language as providing that entities seeking to market installations or community solar subscriptions using Illinois Solar for All contracts must, at a minimum, be certified by the Agency and possess some baseline level of demonstrated competency. The Agency’s approach to vendor certification through its Approved Vendor process is discussed further in Chapters 6 and 8.

As growing the low-income solar market involves more than just REC delivery contracts making photovoltaics more economic, the law also requires that projects “must include job training opportunities if available,” and seeks that such job training opportunities should be effected through coordination with the job training programs proposed in ComEd’s Workforce Development Plan. The Agency’s approach to encouraging that projects use job trainees to help build the low-income solar marketplace is discussed further in Chapter 8.

2.6.4. Illinois Solar for All—Third-party Program Administrator

To assist the Agency in its administration of the Illinois Solar for All Program, Section 1-56(b)(5) provides that the Agency may retain a third-party program administrator (or administrators) through a Request for Qualifications and competitive bid process. The selection criteria and requirements must include, but are not limited to, “experience in administering low-income energy programs and overseeing statewide clean energy or energy efficiency services.”

As both its Illinois Solar for All third-party program administrator and the “expert consulting firms” to assist with implementing and operating the Adjustable Block Program merely “may” be retained, the Agency understands that it could, in theory, use the same entity to assist it with the implementation of both programs (and is not prohibited from using either third-party administrator

¹⁷⁴ Id.

¹⁷⁵ Docket No. 17-0838, Final Order dated April 3, 2018 at 150-151.

¹⁷⁶ 20 ILCS 3855/1-56(b)(2).

to assist it with the implementation of the Community Renewable Generation Program).¹⁷⁷ In September 2018, after the conclusion of its RFQ and RFP process, the Agency entered into a contract with Elevate Energy (“Elevate”) under which Elevate serves as the third-party program administrator for the Illinois Solar for All Program.

2.7 2021 Legislative Proposals

During the Spring 2021 session of the Illinois General Assembly, multiple bills were introduced that would impact the IPA’s planning and procurement processes for not only procuring renewable energy credits, but also supporting the development of additional renewable energy generation more generally. Some of these bills would also seek to address the scheduled refund of over \$300 million originally collected to support renewable energy projects, while also ensuring payment certainty for existing REC delivery contract holders facing payment deferral in the 2021-22 delivery year.

Significant energy bills introduced in the 102nd General Assembly included the following:

- HB 804/SB 1718 (the “Clean Energy Jobs Act”)
- HB 1734/SB 311 (the “Downstate Energy Affordability Act”)
- HB 2640/SB 1601 (the “Path to 100 Act”)
- HB 3446/SB 529 (the “Coal to Solar and Energy Storage Act”)
- HB 1472/SB 1100 (the “Climate Union Jobs Act”)
- HB 4074/SB 2896 (the “Consumers and Climate First Act”)

Through legislative working groups convening across April and May of 2021, interested stakeholders worked diligently toward compromise legislation borrowing elements from each of the above-listed bills. Drafts of omnibus energy bills were produced by legislative staff across the final week of the ILGA’s Spring 2021 session, but that session nevertheless concluded on May 31, 2021 without meaningful legislative advancement. Additional session days were scheduled for June 15-16, 2021, but no progress was made on omnibus energy legislation across that period.

As no legislation significantly reforming the Agency’s statutory long-term renewable resources planning responsibilities has passed as of the time of this Draft Second Revised Plan’s publishing, the Agency will continue to work toward the further development, finalization, and filing of this Plan. The Agency is presently monitoring legislative discussions and has been an active participant in hearings, working group meetings, and other discussions in which its interests and responsibilities are implicated.

Should any legislation pass which significantly modifies the Agency’s responsibilities in developing this Second Revised Plan, the Agency anticipates that any such legislation will clearly address whether this Second Revised Plan development process is rendered moot through statutory changes, most likely through requiring a new Plan development process to develop a Plan reflecting changes in state law enacted through that legislation.

2.8 Legislative Audit Commission Report

Through Resolution No. 153, the Illinois Legislative Audit Commission directed the Auditor General to “conduct a performance audit of the Illinois renewable portfolio standard and the Illinois Power

¹⁷⁷ In its Order approving the Plan, the Commission rejected a proposal requiring that the IPA use separate administrators for the Adjustable Block Program and Illinois Solar for All Program and rejected a proposed requirement that the program administrator and its subcontractors be limited to non-profit entities. See Docket No. 17-0838, Final Order dated April 3, 2018 at 161-164.

Agency's management of the Renewable Energy Credit procurement process and Adjustable Block Grant Program."¹⁷⁸ The Auditor General's Office's report was published on May 11, 2021.

While any such report would not have the force and effect of law, the Illinois Power Agency takes any recommendations offered by the Auditor General's Office very seriously. As that report constitutes a third-party auditor's review of the Agency's activities implementing complex legislation allocating hundreds of millions of dollars of ratepayer funds, any suggestion or recommendation for how to do so in a manner which better serves the public interest should at least merit attention as the Agency develops procurement and planning approaches through this Second Revised Plan.

That report concluded with one recommendation, with which the Agency agreed:

The Illinois Power Agency should continue to work to meet the renewable energy percentage-based procurement goals required by 20 ILCS 3855/1-75(c)(1)(B).

As outlined earlier in this Chapter 2, the Agency proposed a procurement strategy in its Initial Long-Term Plan to attempt to meet the percentage-based procurement goals of Section 1-75(c)(1)(B) of the IPA Act through year-over-year "spot procurements" intended to procure RECs from built and existing projects that qualified for the Illinois RPS with "loose" RECs not otherwise under contract. That procurement approach was rejected by the Commission in Docket No. 17-0838, with instruction that any available budget instead be focused on procurements intended to facilitate the development of new projects (which may not have RECs available to be delivered and retired for many years, given new renewable energy project development timelines).

The Agency's competitive procurement approaches are discussed further in Chapter 5. While the Agency takes the Legislative Audit Commission's recommendation very seriously, the current RPS budget situation—under which, statewide, available funds exceed *already contracted* expenses—does not allow for the proposal of additional procurement events to meet the percentage-based procurement goals of Section 1-75(c)(1)(B). The Agency will continue to monitor the RPS budget situation and may change its proposed scope of procurements should additional funding somehow become available.

¹⁷⁸ The Adjustable Block Program involves REC delivery contracts, with "blocks" referring to a capacity threshold of projects supported, and not "block grants."

3. RPS Goals, Targets, and Budgets

The original Illinois Renewable Portfolio Standard was established in 2007 through Public Act 95-0481 and became effective on June 1, 2008. That RPS set annual percentage goals relative to “eligible retail load” in the state for the procurement of renewable energy resources, starting with at least 2% by the beginning of the 2008-2009 delivery year and rising to 25% by the 2025-2026 delivery year.¹⁷⁹ These goals initially applied only to the load associated with “eligible retail customers”—the residential and small commercial customers who receive fixed-price bundled service from the utilities, rather than switching to hourly priced service or to service from an Alternative Retail Electric Supplier. In 2009, Public Act 96-0033 added Section 16-115D to the Public Utilities Act, which created separate RPS obligations for ARES. The ARES RPS goals were based on the quantity of metered electricity delivered by the ARES to retail customers in Illinois, but with very different compliance mechanisms as explained in Section 2.1.3 above.

P.A. 99-0906 revised the RPS to apply goals to all retail customer load and to phase out the ARES compliance obligations over a two-year period, terminating on May 31, 2019 (see Section 3.2 for more information). These revisions also consolidated the RPS into a single, centralized planning mechanism for procurements and programs as described in this Plan.

The revisions to the RPS include a number of REC procurement goals and targets. As used in this Plan, the Agency considers a “goal” to be an overall percentage of load to be procured in the form of RECs for a given year based upon that year’s mandated RPS requirement.¹⁸⁰ A “target,” on the other hand, is the number of RECs for a specific procurement event or program based upon the specific goal or numerical mandate.

Under the changes to the RPS made via P.A. 99-0906, the annual RPS percentage goal remains the same as was previously found in Section 1-75(c)(1) of the IPA Act—19% for the 2021-2022 delivery year, rising incrementally by 1.5 percentage points annually to 25% by 2025-2026—but this goal is now applied to all retail electricity sales rather than only sales to eligible retail customers. Meeting the RPS goals of the Act for this Second Revised Plan would require procuring an additional approximately 16.45 million RECs for the 2021-2022 delivery year, increasing to the forecasted procurement of an additional 19.8 million RECs for the 2030-2031 delivery year.

In addition, specific REC targets call for various quantities of RECs to be procured in increasing steps starting with the 2017-2018 delivery year through the end of the 2030-2031 delivery year, including:

- 1,000,000 RECs from new utility-scale wind projects and 1,000,000 RECs from new utility-scale and brownfield site solar projects to be delivered annually (with delivery beginning no earlier than June 1, 2019, and no later than June 1, 2021¹⁸¹) procured through the Initial Forward Procurement which was conducted separately from the Initial Plan; and
- A total of at least 2,000,000 RECs delivered annually each from new wind and new photovoltaic projects by the end of the 2020-2021 delivery year, ramping up to 3,000,000

¹⁷⁹ 220 ILCS 5/16-111.5(a).

¹⁸⁰ For example, the RPS “goal” for the 2020-2021 delivery year is 17.5% of the retail load.

¹⁸¹ Public Act 101-0113 allows for an extension of this date if “the project has delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract.” In such a case, the first REC delivery deadline may be extended to “not later than June 1, 2022.”

RECs delivered annually each from new wind and new photovoltaic projects by the end of the 2025-2026 delivery year, and reaching 4,000,000 RECs delivered annually each from new wind and new photovoltaic projects by the end of 2030-2031. (RECs from the Initial Forward Procurement count toward these targets.)

This Chapter contains calculations of RPS targets, summaries of RPS portfolios, and summaries of RPS budgets for delivery years 2022-2023 through 2027-2028. Additional details are available in Appendix B.

3.1. Statewide Goals and Allocation of Cost and RECs from RPS Procurements to Each Utility

The specific numerical targets included in the Act—for instance, the 3,000,000 RECs from new wind and new photovoltaics by 2025-26—are *statewide* targets which do not specify individualized REC targets for each utility. Since the passage of P.A. 99-0906, the Agency has procured RECs through its competitive procurements based on statewide RPS targets rather than individual targets by utility. Contract quantities stemming from those procurements were then assigned to each of the three participating utilities based on an RPS Budget-weighted basis.

For this draft Revised Plan, the Agency proposes to continue conducting the procurement of RECs (if possible, given budget constraints discussed elsewhere in this Chapter) based on statewide RPS goals and targets which, due to changes in load forecasts and the presence of new RECs under contract, have been updated from those contained in prior Plans. The cost of the RECs associated with RPS procurements will be allocated to each utility through REC procurement contracts specific to the applicable utility (and independent of supplier performance under other utilities' contracts), based on each utility's Renewable Portfolio Standard Budget ("RPS Budget").

Table 3-1 shows the proposed allocation across each of the three utilities based on each utility's cost cap rate and eligible load.¹⁸²

¹⁸² This allocation method was initially developed to allocate the RECs from the August 31, 2017 Initial Forward Procurement and was based on the RPS Budget for 2020-2021, which uses the prior year delivered volumes as reference. The 2019-2020 reference delivery year was used because it will be the first year when all load, including that served by ARES, will be under the IPA's REC procurements, thus making the resulting RPS Budget a better representation of future RPS Budgets. As shown in Table 3-1 **Table 3-1**, the allocation to each utility is based on the utility's share of the 2022-2023 delivery year RPS Budget. As noted in Chapter 6, the same allocation will generally be used for the Adjustable Block Program contract awards.

Table 3-1: Utility REC Cost Allocations

Utility	Reference Year Forecasted Delivered Volume [MWh] ¹⁸³	Cost Cap Rate ¹⁸⁴ [\$/MWh]	RPS Budget for 2022-2023 Delivery Year [€] ¹⁸⁵	Allocation Based on RPS Budget for 2022-2023 Delivery Year [%]
Ameren Illinois	35,071,637	1.8054	63,318,333	28.246%
ComEd	84,697,000	1.8917	160,221,315	71.473%
MidAmerican*	507,935	1.2415	630,601	0.281%

*MidAmerican Applicable load, explained in Section 3.4

Under this allocation, for every \$1,000,000 of expenditures made to procure RECs, \$282,460 and associated REC contracts would be allocated to Ameren Illinois, \$714,730 and associated REC contracts to ComEd, and \$2,810 and associated REC contracts to MidAmerican.

3.2. Impact of the Phase out of Alternative Retail Electric Supplier RPS Obligations

P.A. 99-0906 resulted in changes to the requirements for ARES RPS compliance. As outlined in Section 2.1.3, prior to P.A. 99-0906’s revisions to Section 16-115D of the Public Utilities Act, ARES could meet their compliance requirements through Alternative Compliance Payments (“ACP”) or through a combination of ACPs, generation using eligible renewable resources, purchasing electricity generated using eligible renewable resources, and purchasing RECs.

Under the RPS requirements enacted through P.A. 99-0906, after a two-year transition period that ended May 31, 2019, the IPA is now responsible for procuring RECs for virtually all retail load in Illinois, including load served by ARES. Therefore, ARES no longer have an obligation to procure RECs or make ACPs for RPS compliance.¹⁸⁶

3.3. Section 1-75(c)(1)(H)(i) ARES Option to Supply RECs for their Retail Customers

Section 1-75(c)(1)(H) of the Act provides an exception to the phase out of ARES RPS obligations described in Section 3.2. Under this exception, an ARES may use self-supplied RECs to meet a portion (and possibly all) of the REC procurement requirements applicable to its load. To do so, the ARES had to first make an informational filing to the ICC within 45 days of the effective date of Public Act 99-0906 (i.e., within 45 days of June 1, 2017), indicating that it owned a generating facility or facilities as of December 31, 2015, that produced RECs eligible to meet the RPS, provided that those facilities were not powered by wind or solar photovoltaics.

¹⁸³ The 2021-2022 delivery year is the reference year for the 2022-2023 delivery year.

¹⁸⁴ The Cost Cap Rate for each utility is defined in Section 1-75(c)(1)(F) of the Act as “the greater of 2.015% of the amount paid per kilowatthour by [eligible retail] customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011.” 2.015% of the bundled price paid per kWh by eligible retail customers in the 2006-2007 delivery year was 0.18054 cents for Ameren Illinois, 0.18917 cents for ComEd, and 0.12415 cents for MidAmerican. The incremental amount per kWh paid for renewable resources in 2011 was 0.00584 cents for Ameren Illinois, and 0.0057 cents for ComEd. MidAmerican did not participate in IPA-administered renewable energy procurements in 2011; therefore, it did not have an incremental amount for that year.

¹⁸⁵ Beginning with the 2019-2020 delivery year, the RPS Budget for each utility is calculated by multiplying the values of the preceding two columns of the table, as specified by Section 1-75(c)(1)(F) of the Act (“To arrive at a maximum dollar amount of renewable energy resources to be procured for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered [...] by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory.”).

¹⁸⁶ 220 ILCS 5/16-115D(i).

The amount of RECs that can be supplied by ARES-owned/ generation is subject to several limitations. Specifically, the Act provides that:

*“For the delivery year beginning June 1, 2018, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 25% multiplied by 14.5% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016.”*¹⁸⁷

*“For delivery years beginning June 1, 2019 and each year thereafter, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 50% multiplied by 16% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016, provided that the 16% value shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.”*¹⁸⁸

The Act limits the total amount of RECs that can be supplied by all ARES through owned generation:

*“For each delivery year, the total amount of renewable energy credits supplied by all alternative retail electric suppliers shall not exceed 9% of the Illinois target renewable energy credit quantity. The Illinois target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered in the delivery year immediately preceding that delivery year, provided that the 14.5% shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.”*¹⁸⁹

In order to take into account the self-supply by the ARES, the Act requires that the charges which are applicable to the retail customers of the ARES be reduced by the ratio of the RECs supplied by the ARES to the ARES's RPS target. Specifically, the Act states that:

“If the requirements set forth in items (i) through (iii) of this subparagraph (H) are met, the charges that would otherwise be applicable to the retail customers of the alternative retail electric supplier under paragraph (6) of this subsection (c) for the applicable delivery year shall be reduced by the ratio of the quantity of renewable energy credits supplied by the alternative retail electric supplier compared to that supplier's target renewable energy credit quantity. The supplier's target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered by the alternative retail supplier in that delivery year, provided that the 14.5% shall increase by 1.5% each

¹⁸⁷ 20 ILCS 3855/1-75(c)(1)(H)(iii).

¹⁸⁸ Id.

¹⁸⁹ Id.

delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.”¹⁹⁰

The ARES must also notify the Agency and the applicable utility by February 28 of each year of its election to supply RECs to its retail customers and include the amount of RECs to be supplied. By April 1 of each year, the IPA posts a report to its website outlining on the aggregate number of RECs being supplied by the ARES for the upcoming delivery year under this provision, starting June 1.¹⁹¹ This quantity is accounted for as RECs from “other technologies” (i.e., other than wind or solar) and reduces the overall RPS Target for that delivery year. Those targets are shown (unadjusted) in Table 3-13.

One ARES informational filing, covering an eligible ARES-owned generation facility located outside of Illinois, was submitted on a confidential basis to the ICC by the deadline of July 15, 2017.

3.4. MidAmerican Volumes

While procurement plans are required to be prepared annually for Ameren Illinois and ComEd, Section 16-111.5(a) of the PUA states that “[a] small multi-jurisdictional electric utility . . . may elect to procure power and energy for all or a portion of its eligible Illinois retail customers” in accordance with the planning and procurement provisions found in the IPA Act. On April 9, 2015, MidAmerican first formally notified the IPA of its intent to procure power and energy for a portion of its eligible retail customer load through the IPA through its participation. That portion is essentially the incremental load that is not forecasted to be supplied in Illinois by what MidAmerican, a vertically-integrated utility in Iowa that owns generation there (as well as a share of the Quad Cities nuclear plant in Cordova, IL), assigns to Illinois as its jurisdictional generation. Each year since, MidAmerican has remained a part of that process to meet the remaining “portion” of its load.

MidAmerican’s status as a multi-jurisdictional utility that uses its own generating resources to meet a portion of its Illinois load creates a unique situation for RPS compliance. Unlike Ameren Illinois and ComEd, for which all retail load is subject to the RPS goals and targets (subject to limited exceptions outlined above), the MidAmerican load for which the RPS goals and targets are applicable has traditionally been only that load that is subject to the IPA’s annual planning and procurement process for conventional power. As mentioned above, that amount has been the forecast load in excess of MidAmerican’s Illinois-allocated generation in any given delivery year, which has generally been only 25-35% of its total jurisdictional load.¹⁹²

As a significantly smaller Illinois utility to begin with, and with only a portion of its load applicable to the Illinois RPS, the MidAmerican share of Illinois RPS and Zero Emission standard contracts has often been only a fraction of that allocated to ComEd and Ameren Illinois.

¹⁹⁰ Id.

¹⁹¹ For the 2021-2022 delivery year, see: <https://www2.illinois.gov/sites/ipa/Documents/2021-2022%20Delivery%20Year%20ARES%20REC%20Report.pdf>. The amount of RECS expected to be supplied is 1,704,547.

¹⁹² The Commission specified this approach for the procurement of renewable resources to meet the RPS compliance targets applicable to MidAmerican in Docket No. 15-0541, determining that only the portion of MidAmerican’s load subject to the IPA’s planning and procurement process is subject to Section 1-75(c) of the Act’s requirements.

3.4.1. Change to MidAmerican’s Load Forecast Methodology

In 2018, MidAmerican proposed and the Commission approved a change in approach to forecast MidAmerican’s generation used for electricity procurement.¹⁹³ This change caused a sudden and significant reduction of the load subject to the IPA electricity procurement process, as seen in Table 3-2 below.

Table 3-2: MidAmerican Applicable Load and RPS Budget before and after Change in Forecast Approach

Compliance Delivery Year	Reference Delivery Year	Applicable Load Before Change [MWh] ¹⁹⁴	Applicable Load After Change [MWh] ¹⁹⁵	RPS Budget Before Change [\$]	RPS Budget After Change [\$]
2020-2021	2019-2020	616,844	0	765,812	0
2021-2022	2020-2021	527,768	0	655,224	0
2022-2023	2021-2022	519,093	126	644,454	156
2023-2024	2022-2023	509,457	400	632,491	497
2024-2025	2023-2024	390,919	644	485,326	800
2025-2026	2024-2025	372,831	929	462,870	1,153

In the 2019 Electricity Procurement Plan, the IPA explained the change in approach to forecast MidAmerican’s generation:

In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2019 Plan, the IPA notes that MidAmerican revised the methodology used for its generation supply forecast. The prior forecast methodology utilized production cost models to dispatch the Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The revised methodology is based on the utilization of MISO Unforced Capacity (“UCAP”) from the baseload Illinois Historical Resources to determine the generation available to meet MidAmerican’s Illinois eligible load.¹⁹⁶

MidAmerican’s revised methodology utilizes the full capability of each baseload generation asset, represented by the UCAP MW values as determined by MISO for each year’s Planning Resource Auction. The UCAP values de-rate generating unit capabilities by considering historical forced outage rates and operating conditions under summer peak conditions. The IPA, for the 2019 Plan, recommends no changes to the determination of monthly on-peak and off-peak block energy requirements other than the replacement of generation production values with the UCAP values for each of the following baseload resources:

- *Coal resources including: Neal Unit #3, Neal Unit #4, Walter Scott Unit #3, Louisa Generating Station, and Ottumwa Generating Station.*

¹⁹³ Docket No. 18-1564, Final Order dated November 26, 2018.

¹⁹⁴ Based on load volumes presented in the Initial Plan.

¹⁹⁵ Based on volumes provided by MidAmerican in its response submitted for the preparation of the First Revised Plan.

¹⁹⁶ MidAmerican allocates 10.86% of the UCAP ratings of its baseload units for Illinois Historical Generation.

- *Nuclear Resources: Quad Cities Nuclear Power Station.*

The supply capability that is determined is netted against the forecast of MidAmerican Illinois load to calculate the monthly on-peak and off-peak shortfalls which will be met with energy block purchases in the IPA procurements. In determining the amount of block energy products to be procured for MidAmerican, the IPA treats the allocation of capacity and energy from MidAmerican's Illinois Historical Resources in a manner analogous to a series of standard energy blocks. This approach is consistent with the 2018 Procurement Plan approved by the Commission.

As shown in Table 3-2 above, one unintended consequence of this reduction is that it would cause the annual commitments of already procured RECs and associated spending to exceed MidAmerican's projected RPS annual budget using the prior-applied methodology for determining that budget amount. Stated differently, MidAmerican was previously assigned contracts assuming it would have ~\$650,000 available to spend annually on renewable energy procurement. Upon those obligations becoming due and payments needing to be made, applying MidAmerican's new load forecasting methodology in combination with the prior approach to determining MidAmerican's RPS budget would result in MidAmerican only potentially having hundreds of dollars available for renewable energy resource procurement.

This could have left entities holding contracts with MidAmerican at risk of non-payment, as absent an alternative interpretation to calculating MidAmerican's available RPS budget, MidAmerican would not be authorized to meet those contract obligations without exceeding its statutory RPS rate impact cap. This situation could have caused some new renewable energy facilities dependent on revenue from MidAmerican's contracts to suffer losses, leaving them potentially unable to generate enough revenue to cover costs.

3.4.2. Correcting for the Unintended Consequences of MidAmerican's Changed Forecast Approach

As described in more detail throughout Chapter 2, a primary objective informing Public Act 99-0906's reforms to the Illinois RPS was to reduce year-over-year funding volatility that effectively paralyzed leveraging RPS funds to support the development of new renewable energy generation. While such volatility was not completely eliminated, year-over-year RPS annual budget changes for those utilities remain relatively minor, and enough stabilization was introduced to allow for the execution of the types of long-term contracts providing sufficient revenue certainty to allow developers to secure financing to develop new renewable generation. To ensure similar stability for MidAmerican's budgets, in the First Revised Plan, the IPA proposed and the Commission accepted the use of a proxy to calculate MidAmerican's Applicable Load. This proxy for applicable load is a percentage of MidAmerican's total Illinois retail load.

MidAmerican's Applicable Load for the purposes of RPS compliance (i.e., calculations of REC targets, budgets, and allocation of REC contracts in this Second Revised Plan) is to be fixed at 26.025% of MidAmerican's annual total Illinois retail load. This percentage is calculated as follows: the average of MidAmerican's applicable load from the Initial Plan for the DYs 2019-2020 through 2037-2038 is 526,880 MWh. The average of the total retail load provided by MidAmerican in their July 2019 data response for the same period is 2,024,484 MWh. The ratio of the average applicable load from the

Initial Plan to the average total retail load provided by MidAmerican in its data response yields a 26.025% proxy.

Adopting this proposal produces Applicable Load volumes that are equivalent to those used in the Initial Plan, as shown on Table 3-3, which formed the basis to calculate MidAmerican's targets and budgets that supported MidAmerican's allocation of REC contracts and corresponding spending. Additionally, as can be observed in the Table below, MidAmerican's resulting Applicable Load and corresponding budget is relatively stable, year over year, helping to ensure not only that existing contracts are not curtailed, but also that the year to year volatility that resulted in years of advocacy to "fix" a "broken" RPS does not persist for MidAmerican.

As this proposal was uncontested in Docket No. 19-0995, the IPA understands this proposal to have been adopted by the Commission through its Final Order in that proceeding approving the First Revised Plan. This approach will be maintained for this Second Revised Plan.

Table 3-3: Comparison of MidAmerican’s Applicable Load Using the Generation Forecast before Change and the Proposed Proxy for Determining Applicable Load and Budget

Compliance Delivery Year	Reference Delivery Year	Applicable Load Before Change August 1, 2017 [MWh] ¹⁹⁷	RPS Budget Before Change August 1, 2017 [\$] ¹⁹⁸	Applicable Load Using Proxy [MWh] ¹⁹⁹	RPS Budget Using Proxy [\$]
2019-2020	2018-2019	704,364	874,468	528,791	656,494
2020-2021	2019-2020	616,844	765,812	517,599	642,599
2021-2022	2020-2021	527,768	655,224	518,437	643,640
2022-2023	2021-2022	519,093	644,454	519,350	644,774
2023-2024	2022-2023	509,457	632,491	520,308	645,963
2024-2025	2023-2024	390,919	485,326	521,252	647,135
2025-2026	2024-2025	372,831	462,870	522,222	648,338
2026-2027	2025-2026	475,331	590,123	523,149	649,490
2027-2028	2026-2027	395,422	490,916	524,135	650,713
2028-2029	2027-2028	472,535	586,652	525,148	651,972
2029-2030	2028-2029	432,084	536,432	526,220	653,302
2030-2031	2029-2030	396,202	491,885	527,567	654,974
2031-2032	2030-2031	405,524	503,458	529,097	656,875
2032-2033	2031-2032	386,254	479,534	530,592	658,730
2033-2034	2032-2033	556,310	690,659	532,165	660,683
2034-2035	2033-2034	795,579	987,711	533,702	662,592
2035-2036	2034-2035	706,470	877,083	535,287	664,559
2036-2037	2035-2036	693,364	860,811	536,991	666,675
2037-2038	2036-2037	654,366	812,395	538,704	668,801
Total All Years		10,010,717	12,428,305	10,010,717	12,428,305

For the balance of this Second Revised Plan, MidAmerican’s Applicable Load will be determined by using the proxy approach proposed in this Section.

¹⁹⁷ Based on load volumes presented in the Initial Plan.

¹⁹⁸ Budget used in the Initial Plan.

¹⁹⁹ Applicable Load equals 26.025% of Forecast Retail Load.

3.5. Cost Cap and Cost Recovery

The IPA’s procurement of RECs on behalf of Illinois electric utilities is subject to monetary limitations in the form of a cost cap that limits the annual average net increase to all eligible retail customers to “no more than the greater of 2.015% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt-hour paid for these resources in 2011.”²⁰⁰ On a percentage basis, the cost cap determined under these criteria is unchanged from the RPS cost cap predating Public Act 99-0906; however, it is now applied to the actual quantity of electricity delivered in the prior delivery year to all applicable retail customers in the utility’s service territory.²⁰¹ The cost cap rate, in cents per kilowatt-hour, is provided in Table 3-4.

Table 3-4: REC Procurement Cost Cap Rate by Utility²⁰²

Utility	RPS Cost Cap Rate [¢/kWh]
Ameren Illinois	0.18054
ComEd	0.18917
MidAmerican	0.12415

Each utility is entitled to recover the costs of the RECs procured to meet the RPS compliance requirements, subject to the cost cap limitations, along with “...the reasonable costs that the utility incurs as part of the procurement process and to implement and comply with plans and processes approved by the Commission...”²⁰³

Since the start of the 2017-2018 delivery year, the utilities are able to recover all of their costs—whether associated with RECs previously procured through prior-executed contracts, procured through the Initial Forward Procurements, procured through other competitive procurements, or procured through the other programs resulting from the implementation of the IPA’s long-term renewable resource procurement plans²⁰⁴—through tariffs applicable to all of the utilities’ customers. These tariffs took effect as of the June 2017 billing period and allow collections by utilities to recover the costs of RECs procured by the IPA. The Commission will conduct a single review, reconciliation and true-up of the utility’s collections covering REC costs for the 2017-2018, 2018-2019, 2019-2020, and 2020-2021 delivery years no earlier than August 31, 2021.²⁰⁵

As discussed later in this Chapter 3, because collections to date have been significantly greater than expenses incurred through the first four delivery years since P.A. 99-0906 became effective, absent a change in state law, this reconciliation is expected to result in a considerable refund to customers of hundreds of millions of dollars previously collected to support renewable energy resource procurement.

²⁰⁰ 20 ILCS 3855/1-75(c)(1)(E).

²⁰¹ Id.

²⁰² These figures are the same rates used in the IPA’s 2017 Electricity Procurement Plan approved by the Commission. See: https://www2.illinois.gov/sites/ipa/pages/Prior_Approved_Plans.aspx at 12.

²⁰³ 220 ILCS 5/16-108(k).

²⁰⁴ For which the utility is the counterparty; for the Illinois Solar for All Program, the State of Illinois is (or will be) the counterparty to many REC delivery contracts with those payments funded using the Renewable Energy Resources Fund.

²⁰⁵ See id.

3.6. RPS Compliance Procurement Priorities

The Act provides guidelines for prioritizing the REC procurements in the event that the cost cap limitations conflict with the RPS goals and targets such that the IPA cannot procure sufficient additional quantities of RECs to meet goals or targets.²⁰⁶ Under Section 1-75(c)(1)(F) of the IPA Act, these priorities regarding the procurement of RECs take the following order, arranged based on descending priority:

- RECs procured under existing contracts;
- RECs procured with funding for the Illinois Solar for All Program;
- RECs procured to comply with the new wind and solar photovoltaic procurement requirements (including the Adjustable Block Program);
- RECs procured to meet the remaining RPS targets (REC Gap).

Faced with RPS budget constraints for the 2021-22 delivery year under which expenses from REC delivery contracts are projected to outpace available collections (largely because, as outlined in Section 3.5 above, funds collected from June 2017 through May 2021 cannot be leveraged to meet RPS expenses incurred after June 1, 2021), the IPA petitioned the ICC to reopen Docket No. 19-0995 approving the Agency's First Revised Plan. Reopening allowed for the institution of a uniform, Commission-authorized payment deferral regime in the case that REC delivery contract payments could not be met through available funds. Through the ICC's resulting Order on Reopening, the Commission gave effect to the priorities outlined under Section 1-75(c)(1)(F) by exempting REC delivery contracts executed prior to June 1, 2017 and all existing and projected Illinois Solar for All REC delivery contracts from payment deferrals required to ensure that delivery year RPS expenses do not exceed collections.

3.7. Wind/Solar Matching Requirement and Solar Split

The Act defines the annual REC targets for wind and solar generation in terms of the timing of the annual quantities to be procured and the technology preferences for the facilities generating the RECs.²⁰⁷ The overall quantity of RECs procured to meet the RPS goals must include at least a combined 75% from wind and photovoltaic projects.

In addition to the wind and photovoltaic requirements that apply to the overall RPS goals, the Act also contains specific numerical targets that apply to RECs from "new" wind and new photovoltaic projects ("new" projects are those projects energized after June 1, 2017).²⁰⁸ Targeted REC deliveries from new projects for each generating technology are 2,000,000 RECs by the end of the 2020-2021 delivery year, 3,000,000 RECs by the end of the 2025-2026 delivery year, and 4,000,000 RECs by the end of the 2030-2031 delivery year. The new photovoltaic project REC procurement targets are further broken down to require at least 50% of these targets from distributed photovoltaic renewable generation projects or photovoltaic community renewable generation projects using the Adjustable Block Program, at least 40% from utility-scale photovoltaic projects, at least 2% from

²⁰⁶ 20 ILCS 3855/1-75(c)(1)(F).

²⁰⁷ 20 ILCS 3855/1-75(c)(1)(C).

²⁰⁸ The IPA, in accounting for RECs from new projects towards the Section 1-75(c)(1)(C) REC targets, excludes RECs procured through the DG Procurements in 2017 because of their relative small quantity and uncertainty around their energized date. They are, however, included in compliance calculations to ensure that at least a combined 75% of RECs be from wind and photovoltaic projects.

brownfield site photovoltaic projects that are not community solar projects, and the remaining 8% not specified but determined through this Plan.

Furthermore, the total amount of RECs targeted for delivery from all new wind projects is not to exceed the total amount of RECs to be delivered from all new photovoltaic projects. In the event that the projected cumulative quantity of new wind project RECs to be delivered exceeds the quantity of new solar project RECs projected to be delivered by 200,000 RECs or more, procurement targets will be adjusted as needed to bring the wind and solar REC quantities back into balance.²⁰⁹ Per the definition of “new photovoltaic projects” in the Act, RECs procured as part of the Illinois Solar for All Program (see Chapter 8) cannot be counted as new photovoltaic RECs for purpose of meeting Section 1-75(c)(1)(C)’s quantitative targets and therefore are not accounted as such in this Second Revised Plan, although these RECs would count toward the overall 75% of RECs coming from wind or photovoltaic resources.

Table 3.5 shows the breakdown of expected REC deliveries from procurements held to date as well as RECs from Adjustable Block Program projects. The table accounts for utility-scale projects from prior procurements (discussed further in Section 3.9) that were not energized by their applicable deadline. The increase in solar RECs between the 2021-2022 delivery year and the 2022-2023 delivery year reflects energization of remaining approved projects that have not yet been energized. The quantity of RECs from new wind projects does not exceed those from new solar projects.

Table 3-5: Expected New Project REC Deliveries

Delivery Year	Adjustable Block Program RECs	Utility-Scale Solar RECs	All Solar RECs	All Wind RECs	Solar In Excess of Wind
2021-22	679,194	1,386,448	2,065,642	2,065,519	123
2022-23	1,161,029	2,522,674	3,683,702	2,065,519	1,618,183
2023-24	1,177,870	2,505,630	3,683,499	2,065,519	1,617,980
2024-25	1,177,669	2,505,630	3,683,298	2,065,519	1,617,779
2025-26	1,177,476	2,505,630	3,683,105	2,065,519	1,617,586
2026-27	1,177,267	2,505,630	3,682,896	2,065,519	1,617,377
2027-28	1,177,068	2,505,630	3,682,697	2,065,519	1,617,178
2028-29	1,176,871	2,505,630	3,682,500	2,065,519	1,616,981
2029-30	1,176,668	2,505,630	3,682,297	2,065,519	1,616,778
2030-31	1,176,482	2,505,630	3,682,111	2,065,519	1,616,592
2031-32	1,176,281	2,505,630	3,681,910	2,065,519	1,616,391

In its Order approving the Initial Plan, the Commission confirmed that this balancing or “matching” requirement becomes effective as of June 1, 2021 (the last point at which projects from the Initial Forward Procurements can begin delivery of RECs).²¹⁰ Since that time, Public Act 101-0113 was signed into law, which extends the last point at which projects from the Initial Forward Procurements

²⁰⁹ Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

²¹⁰ 20 ILCS 3855/1-75(c)(1)(B), (C).

can begin delivery of RECs to “not later than June 1, 2022” should the project feature “delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract.” As discussed in Chapter 2, this change in state law thus extends the applicable date for the “matching” requirement taking effect out to June 1, 2022.

Based on the current balance of RECs under contract and ongoing RPS budget constraints limiting additional program activity or additional procurement events, the IPA anticipates compliance with this matching requirement across the planning period covered by the Second Revised Plan. Starting in June 2022, the Agency will publish quarterly updates of the status of this matching requirement on its website.

3.8. REC Portfolio

For the planning and development of the various procurements and programs under this Second Revised Plan, it is necessary to aggregate the utility level portfolios of all existing RECs under contract, including/in addition to all expected RECs under the Adjustable Block Program and under contract through competitive procurements, into a single, statewide portfolio of RECs. That resulting statewide portfolio can then be examined against REC goals and targets mandated in the Act to estimate gaps that need to be closed through future procurement of RECs.

The following sections examine existing REC portfolios and the resulting statewide REC Portfolio after accounting for expected deliveries of RECs resulting from the planned Forward Procurement of utility-scale wind RECs, and the balance of the Adjustable Block Program.

3.9. Existing REC Portfolios - RECs Already Under Contract

The tables that follow show the existing REC portfolio of each utility and the aggregated statewide portfolio as of August 16, 2021.²¹¹ The following glossary applies to these tables:

- “LTPPA” includes RECs procured under the Long-Term Power Purchase Agreements entered into in 2010 (these do not count toward the matching requirement described in Section 3.7 above);
- “Legacy DG” includes RECs procured under the Distributed Generation procurement events conducted by the IPA in 2015, 2016, and 2017;
- “Forward Procurements” include RECs procured under the initial forward procurements and the procurement events conducted to date by the IPA pursuant to the Initial Plan;
- “IPA Programs Solar” includes existing RECs procured and under contract resulting from the Adjustable Block Program and the Illinois Solar for All Program as of August 1, 2021.

As discussed further below, the Total RECs under contract has declined relative to the IPA’s April 20, 2020 Final First Revised Plan as these tables now account for project attrition (i.e., projects under REC delivery contracts not planning to be developed, or otherwise not planning to perform under REC delivery contracts) from projects receiving REC delivery contracts under the IPA’s Forward Procurement events.

²¹¹ ILSFA REC commitments have been included in the utilities’ existing REC portfolios (where a utility is contractual counterparty) .

Table 3-6: Ameren Illinois Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs ²¹²	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2021-22	596,571	3,429	2,838	605,816	269,293	315,984	1,202,387	591,545	1,793,932
2022-23	596,571	3,429	327	605,816	734,900	328,237	1,202,387	1,066,893	2,269,280
2023-24	596,571	3,429		605,816	734,900	328,226	1,202,387	1,066,555	2,268,942
2024-25	596,571	3,429		605,816	734,900	328,217	1,202,387	1,066,546	2,268,933
2025-26	596,571	3,429		605,816	734,900	328,205	1,202,387	1,066,534	2,268,921
2026-27	596,571	3,429		605,816	734,900	328,195	1,202,387	1,066,524	2,268,911

Table 3-7: ComEd Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs ²¹³	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2021-22	1,233,838	27,887	18,445	1,452,887	645,828	806,382	2,686,725	1,498,542	4,185,267
2022-23	1,233,838	27,887	5,286	1,452,887	1,762,460	819,456	2,686,725	2,615,089	5,301,814
2023-24	1,233,838	27,887		1,452,887	1,762,460	819,382	2,686,725	2,609,729	5,296,454
2024-25	1,233,838	27,887		1,452,887	1,762,460	819,307	2,686,725	2,609,654	5,296,379
2025-26	1,233,838	27,887		1,452,887	1,762,460	819,238	2,686,725	2,609,585	5,296,310
2026-27	1,233,838	27,887		1,452,887	1,762,460	819,159	2,686,725	2,609,506	5,296,231

²¹² Including Brownfield Site Photovoltaics.

²¹³ Including Brownfield Site Photovoltaics.

Table 3-8: MidAmerican Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs ²¹⁴	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2021-22			449	6,816	3,030	4,011	6,816	7,490	14,306
2022-23				6,816	8,269	4,011	6,816	12,280	19,096
2023-24				6,816	8,269	4,011	6,816	12,280	19,096
2024-25				6,816	8,269	4,011	6,816	12,280	19,096
2025-26				6,816	8,269	4,011	6,816	12,280	19,096
2026-27				6,816	8,269	4,011	6,816	12,280	19,096

The RECs under contract from utility-scale procurements held in 2017 and 2018 listed for this draft Second Revised Plan have been updated from the First Revised Plan to account for project attrition. While four wind projects and two utility-scale solar projects have begun delivery, with three additional utility-scale solar projects excepted to begin delivery imminently, other projects have not been energized. Five solar projects have requested energization extensions that will take them into 2022-2023 delivery year, and four solar projects and two wind projects have not been completed and have been thus been removed from the REC portfolio. The result of the attrition of wind projects has resulted in the portfolio falling below the wind target for the 2025 delivery year and Chapter 5 includes a discussion of a proposed procurement to meet this shortfall. Table 3-9 summarizes in aggregate the status of RECs from utility-scale projects. The quantities listed are the annual contracted amounts.

Table 3-9: Utility-Scale REC Portfolio Status

Status	Solar RECs	Wind RECs	Total RECs
Delivering RECs	410,000	2,065,519	2,475,519
Pending Energization	453,820		453,820
Extensions Granted	1,587,478		1,587,478
Total Expected RECs	<u>2,451,298</u>	<u>2,065,519</u>	<u>4,516,817</u>
2025 REC Target	1,200,000	3,000,000	
Removed ²¹⁵	548,702	879,234	1,427,936

The attrition rate for the Adjustable Block Program has been low, at approximately 1.2% of contracted Small DG projects, 9.8% of contracted Large DG projects, and 7.2% of contracted

²¹⁴ Including Brownfield Site Photovoltaics.

²¹⁵ "Removed" indicates RECs that were procured in the 2017 and 2018 procurements but will not be delivered because of the projects not meeting energization deadlines and thus have been removed from the RPS REC Portfolio.

community solar projects.²¹⁶ Unlike with utility-scale projects, for which it is not possible to select additional projects without holding an additional procurement, the Adjustable Block Program has rolling applications (and currently waitlists) to fill capacity with newly-selected projects.

3.10. 2019 and 2021 Forward Procurements

In accordance with competitive procurements approved in the Initial Plan, the Agency conducted two competitive procurements events in the Fall of 2019: the Second Subsequent Forward Procurement for utility-scale wind projects (described in Section 5.8.2 of the Initial Plan), and the Community Renewable Generation Program Forward Procurement (described in Section 5.8.4 of the Initial Plan). Neither of these procurement events resulted in the procurement of RECs. In the Spring of 2021, the Agency also conducted an additional utility-scale wind forward procurement; that procurement event also did not result in the procurement of RECs.

3.11. Statewide REC Portfolio

The utilities’ existing REC portfolios produce the Statewide REC Portfolio presented in Table 3-10. This table indicates the volume of RECs expected to be available to meet the various RPS goals and targets mandated in the Act without new authorization for additional procurements or program capacity.

These tables do not constitute the IPA’s projections of progress toward RPS goals in upcoming delivery years; they merely reflect the Statewide REC Portfolio given REC delivery contracts presently in place. As RPS budget funds become available in future delivery years, the IPA anticipates proposing (and receiving ICC approval for) additional program activity and procurement events that would serve to significantly increase the balance of RECs under contract in future delivery years.

Table 3-10: Statewide REC Portfolio (By Expected Delivery Date)

Del. Year	Existing Wind RECs	Existing Solar RECs	Balance of ABP Solar RECs (estimate) ²¹⁷	Total Wind RECs ²¹⁸	Total Solar RECs	Total All RECs
2021-22	3,895,928	2,097,576	3,280	3,895,928	2,100,856	5,996,784
2022-23	3,895,928	3,694,262	3,280	3,895,928	3,697,542	7,593,470
2023-24	3,895,928	3,688,564	3,280	3,895,928	3,691,844	7,587,772
2024-25	3,895,928	3,688,480	3,280	3,895,928	3,691,760	7,587,688
2025-26	3,895,928	3,688,399	3,280	3,895,928	3,691,679	7,587,607

²¹⁶ Community solar project attrition is largely due to projects receiving high updated interconnection cost updates from the applicable utility and thus electing to withdraw from the program.

²¹⁷ This reflects ABP RECs from current blocks not under contract as of the release of this draft Second Revised Plan. These are RECs related to projects that were previously under contract and not completed by their energization date and are in the process of being replaced with projects from the applicable waitlists.

²¹⁸ These totals reflect quantities from the LTPPAs, which do not count against Section 1-75(c)(1)(G)(iv)’s balancing requirement (as these are not from “new” projects, as that term is defined in the Act); as a result, these totals do not demonstrate that the 200,000 REC wind/solar balancing requirement is expected to be exceeded.

3.12. Loads, RPS Goals and Targets, and REC Gaps

To start the procurement planning process, it is first necessary to calculate the annual REC targets and gaps to be filled. In the prior Section, a statewide REC portfolio was presented. The REC quantities in that portfolio will be used in conjunction with the REC targets developed in this Section to estimate REC gaps.

3.13. Applicable Retail Customer Load

The table below shows the forecasted retail customer load subject to RPS compliance through the 2027-2028 delivery year.²¹⁹

Table 3-11: Retail Customer Load Applicable to the Compliance Year

Compliance Delivery Year	Reference Delivery Year	Ameren Illinois [MWh]	ComEd [MWh]	MidAmerican [MWh]	Statewide [MWh]
2021-22	2020-21	35,458,611	83,932,000	507,628	119,898,239
2022-23	2021-22	35,071,637	84,697,000	507,935	120,276,572
2023-24	2022-23	34,921,484	85,389,000	507,526	120,818,010
2024-25	2023-24	34,516,762	85,557,000	507,292	120,581,054
2025-26	2024-25	34,327,388	85,473,000	507,355	120,307,743
2026-27	2025-26	34,327,388	85,656,000	507,636	120,491,024

For the forecast quantity used for the 2022-2023 delivery year, the Ameren Illinois load declined 0.04% from the forecast numbers included in the First Revised Plan; for ComEd, it declined by 0.03%; and for MidAmerican it increased by 2.01%. These small changes in forecasted load will have a corresponding minor impact on estimated annual RPS goals and budget collections. The impact of variations in load forecasts is discussed further in Section 3.21.

3.14. RPS Goals and Targets

RPS annual goals are expressed as percentages in Section 1-75(c)(1)(B) of the Act. To determine the number of RECs required to meet the goals (the “Overall RPS Target”), the delivery year RPS goal is applied to the reference year applicable retail customer load (“Applicable Load”) as shown in equation (1).

$$(1) \quad \text{Delivery Year Overall RPS Target} = \text{Delivery Year RPS Goal} * \text{Reference Year Applicable Load}$$

The statewide RPS Goals and Targets for 2022-2023 through 2027-2028 are shown in the table below.

²¹⁹ As customary, in support of the IPA procurement processes, in the summer of 2021 the utilities developed and provided the actual and forecast loads used in this Second Revised Plan.

Table 3-12: Statewide RPS Goals and Targets

Delivery Year	RPS Goal	Reference Year	Reference Year Load (Applicable Load) [MWh]	Overall RPS Target [RECs]
2021-2022	19.0%	2020-2021	119,898,239	22,780,665
2022-2023	20.5%	2021-2022	120,276,572	24,656,697
2023-2024	22.0%	2022-2023	120,818,010	26,579,962
2024-2025	23.5%	2023-2024	120,581,054	28,336,548
2025-2026	25.0%	2024-2025	120,307,743	30,076,936
2026-2027	25.0%	2025-2026	120,491,024	30,122,756

3.15. Overall REC Procurement Targets - REC Gap

The overall number of RECs needed to be procured for each year to meet annual goals, the “REC Gap”, is simply the difference between the RPS Target RECs from Table 3-12 and the total number of RECs in the Statewide REC Portfolio from Table 3-10, as shown below.

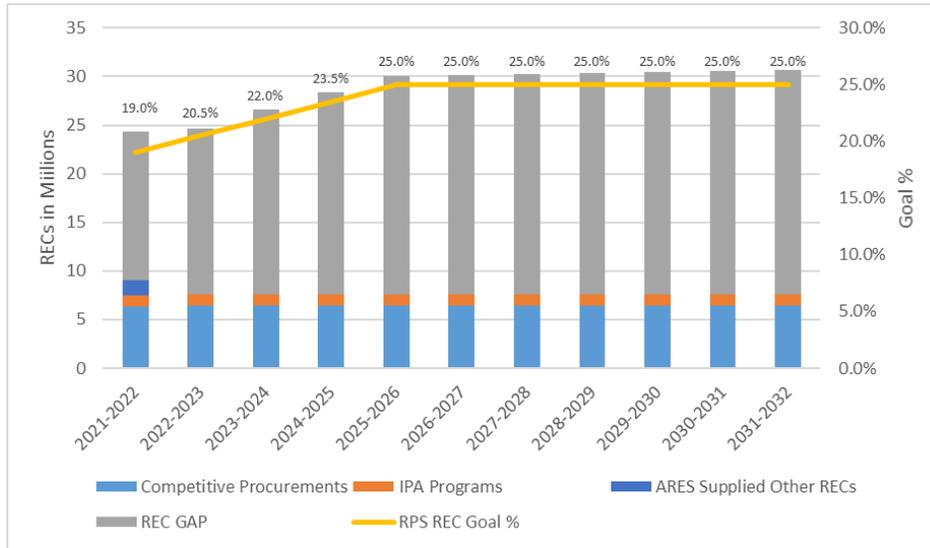
Table 3-13: Statewide Overall REC Gap²²⁰

Delivery Year	Overall RPS Target RECs	Statewide Portfolio Total All RECs	REC Gap
2021-2022	22,780,665	5,996,784	16,783,881
2022-2023	24,656,697	7,593,470	17,063,228
2023-2024	26,579,962	7,587,772	18,992,191
2024-2025	28,336,548	7,587,688	20,748,860
2025-2026	30,076,936	7,587,607	22,489,329
2026-2027	30,122,756	7,587,518	22,535,238

Figure 3-1 below provides a visual representation of the annual Statewide RPS Goals, REC Portfolio, and REC Gap discussed in this Section.

²²⁰ Unadjusted for RECs supplied by ARES.

Figure 3-1: Statewide Annual RPS Goal, REC Portfolio and REC Gap



3.16. Procurement Targets to Meet Specific Wind-Solar Requirement and Overall RPS Targets

Section 1-75(c)(1)(C) of the Act, as explained in Section 2.3.1, requires that the overall quantity of RECs procured to meet the RPS goals must include at least a combined 75% from wind and photovoltaic projects. Table 3-14 below shows that currently nearly the entire portfolio of RECs is made up of RECs from wind and photovoltaic projects.

Table 3-14: Statewide Wind and Solar RECs in the Portfolio

Delivery Year	Total RECs	Wind RECs ²²¹	Solar RECs	Combined Wind and Solar RECs	Percentage of Wind and Solar RECs in Portfolio
2021-2022	5,996,784	3,895,928	2,100,856	5,996,784	100%
2022-2023	7,593,470	3,895,928	3,697,542	7,593,470	100%
2023-2024	7,587,772	3,895,928	3,691,844	7,587,772	100%
2024-2025	7,587,688	3,895,928	3,691,760	7,587,688	100%
2025-2026	7,587,607	3,895,928	3,691,679	7,587,607	100%
2026-2027	7,587,518	3,895,928	3,691,590	7,587,518	100%

²²¹ These totals reflect quantities from the LTPPAs, which do not count against Section 1-75(c)(1)(G)(iv)'s balancing requirement (as these are not from "new" projects, as that term is defined in the Act); as a result, these totals do not demonstrate that the 200,000 REC wind/solar balancing requirement is expected to be exceeded.

3.17. RPS Budget

As described in Section 3.5, the Act imposes monetary limitations on the RPS in the form of a cost cap that limits the annual average net increase in rates to retail customers. The cost cap rate, in cents per kilowatt-hour, is unique to each utility and is provided in Table 3-4. The cents per kilowatt-hour rate is applied to the actual electricity (expressed in kilowatt-hours) delivered in the delivery year immediately prior to determine a maximum dollar amount which constitutes the RPS Budget for the delivery year. Specifically, the Act states that:

“Notwithstanding the requirements of this subsection (c), the total of renewable energy resources procured under the procurement plan for any single year shall be subject to the limitations of this subparagraph (E). Such procurement shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011. To arrive at a maximum dollar amount of renewable energy resources to be procured for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered, or applicable portion of such amount as specified in paragraph (1) of this subsection (c), as applicable, by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory. The calculations required by this subparagraph (E) shall be made only once for each delivery year at the time that the renewable energy resources are procured. Once the determination as to the amount of renewable energy resources to procure is made based on the calculations set forth in this subparagraph (E) and the contracts procuring those amounts are executed, no subsequent rate impact determinations shall be made and no adjustments to those contract amounts shall be allowed. All costs incurred under such contracts shall be fully recoverable by the electric utility as provided in this Section.”²²²

A utility’s annual RPS Budget is calculated as shown in equation (2).

$$(2) \quad \text{Annual RPS Budget (\$/Year)} = \text{Prior Year Delivered Electricity (MWh)} * \text{Cost Cap Rate (\$/MWh)}$$

A utility’s delivery year remaining available net RPS Budget (“Available Net RPS Budget”) is determined by subtracting from the utility’s total RPS Budget the direct financial obligations associated with existing REC contracts (“Contracted REC Spend”), the estimated direct financial obligations associated with the Forward Procurements scheduled for the Fall of 2019 and the balance of the Adjustable Block Program REC procurement authorized under the Initial Plan (“Scheduled REC Spend”), and indirect costs: (i) allocation to fund the Illinois Solar for All Program, (ii) allocation to

²²² 20 ILCS 3855/1-75(c)(1)(E).

fund job training programs, and (iii) set aside for administrative expenses (“Set Asides Allocation”), as shown in equation (3).²²³

$$(3) \quad \text{Delivery Year Available Net RPS Budget} = \text{Annual RPS Budget (equation 2)} - \text{Contracted REC Spend} - \text{Scheduled REC Spend} - \text{Set Asides Allocation}$$

For the purpose of establishing funds available for REC purchases, as explained in the following Section, the Available Net RPS Budget amount will be adjusted prior to any procurement to account for rollover unspent funds from prior years, and utility-held Alternative Compliance Payments.

3.17.1. Utilities Budgets

Table 3-15 through

Table 3-17 show, for each utility, the corresponding RPS Budget, Contracted REC Spend, the allocation of administrative Set Asides including the ILSFA Program allocation, the Available Net RPS Budget, and an estimate of the roll-over balance for delivery years 2021-2022 through 2027-2028. Table 3-19 summarizes those tables at a statewide level.

In addition to direct expenditures on RECs, RPS budgets also feature allocations for several additional purposes, collectively referred to as “Set Asides”. First, pursuant to Section 1-75(c)(1)(O) of the Act, the greater of 5% (of the combined RPS budgets of the utilities) or \$10,000,000 each year will be allocated to the Illinois Solar for All Program. Second, also pursuant to Section 1-75(c)(1)(O), in each of the delivery years 2017-2018, 2021-2022, and 2025-2026, \$10,000,000 of ComEd’s RPS Budget will be allocated to fund solar job training programs pursuant to Section 16-108.12 of the PUA. Under the ICC’s Order on Reopening in Docket No. 19-0995 applying Section 1-75(c)(1)(F) of the Act, these Illinois Solar for All Program allocations are priority expenses to be fully accounted for in determining available budgets for other REC delivery contracts (including Adjustable Block Program and utility-scale project REC delivery contracts already executed).

Third, a reasonable amount of each budget will be set aside for administrative expenses (including, but not limited to, expenses related to development of Plan updates, the management of procurements and programs, Adjustable Block Program Administrator expenses not covered by fees charged to participants, and fees charged by tracking systems for the retirement of RECs). The IPA, for its Revised Plan on Reopening, proposes to set aside 0.65% of the budget for these administrative expenses, and will refine this Set Aside as more information becomes available.²²⁴

Table 3-18 shows the annual RPS funds to be allocated to each of these Set Asides.

The estimated expenditures presented in these tables are estimates that assumes projects currently contracted to produce RECs are successfully completed and deliver RECs in accordance with the

²²³ In the event that the cost cap limitations conflict with the RPS goals and targets such that the IPA cannot procure sufficient additional quantities of RECs to meet the RPS goals or targets, priority for procurement shall first be given to RECs under existing contractual obligations, followed by RECs for the Illinois Solar for All Program, followed by RECs necessary to comply with the new wind and solar procurement requirements, and finally RECs necessary to meet the remaining RPS requirements. 20 ILCS 3855/1-75(c)(1)(F). In its Order approving the Initial Plan, the Commission determined that “such a conflict is possible” if the Agency were to conduct procurements to meet the remaining RPS requirements (i.e., the annual goals found in Section 1-75(c)(1)(B) of the Act), and thus granted various parties’ requests to cancel those procurements. Docket No. 17-0838, Final Order dated April 3, 2018 at 41-42.

²²⁴ The percentage set aside for administrative expenses assumes a retirement fee of 5 cents per REC and an estimated one million dollars for program administration cost annually.

schedule shown in Table 3-10.²²⁵ Additionally, the estimates assume that, for community solar projects in the Adjustable Block Program, such projects satisfy the high end of adders for small subscribers (i.e., all applicable projects have over 75% small subscribers by capacity). This allows these tables to portray the most constrained view of RPS budgets, which the Agency believes is the appropriate approach to take for planning purposes. Should additional projects fail to become energized, or should community solar subscription mixes change, it is possible that actual expenditures will be lower.

From the 2017-2018 delivery year up until the 2020-2021 delivery year, RPS funds collected by the utilities and not spent each year were effectively “rolled over” to be available for the next delivery year. Because the first two years of collections primarily saw the development of the Initial Plan and building out programs for implementation, and because projects from competitive procurements have generally not yet begun making deliveries, significant balances have accrued for the utilities to date. Funds from this four-year period not spent by the end of the 2020-2021 delivery year will be refunded to customers per Section 16-108(k) of the PUA. The potential amounts of those refunds are shown in the top cell (corresponding to 2020-2021) of the Remaining RPS Funds Balance column of Table 3-15 through

Table 3-17. For the same reason, the Accumulated RPS Funds Balance column has no values for delivery years *after* 2020-2021.

The Remaining RPS Funds Balance at end of DY in the tables below do not include the ACPs held by the utilities²²⁶ These ACP funds are potentially available to fill the shortfalls listed for delivery years 2021-2022 through 2023-2024. As of August 16, 2021, Ameren Illinois has \$34,458,408 in uncommitted ACPs, and ComEd has \$66,998,859. As shown in Table 3-15 and

Table 3-16, based on present load forecasts and cost assumptions, these amounts would be just be sufficient enough to cover the total projected shortfalls for Ameren Illinois and would be insufficient for ComEd, which will require the consideration of the payment deferral mechanism discussed in Section 3.24.3 below in order to shift costs forward to future years when utility RPS collections will be sufficient to meet obligations.

For further discussion of the use of the utility-held ACPs, see Section 3.19.

²²⁵ This estimate includes a downward adjustment from the First Revised Plan to account for utility-scale projects that have not met their energization deadlines or requested extensions as of the publication of this draft Second Revised Plan.

²²⁶ ACPs were collected either from hourly pricing customers prior to June 1, 2017 or from ARES for their RPS obligations after June 1, 2017.

Table 3-15: Ameren Illinois RPS Budget (\$)

DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend ²²⁷	Set Asides ²²⁸	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
21-22	64.0	64.0	84.5	0.2	4.4	89.1	(25.1)	34.5	25.1
22-23	63.3	63.3	64.5	0.1	4.4	69.1	(5.8)	9.4	5.8
23-24	63.0	63.0	59.0	0.1	4.5	63.6	(0.6)	3.6	0.6
24-25	62.3	62.3	49.3	0.1	4.4	53.9	8.4	3.1	-
25-26	62.0	62.0	20.8	0.1	4.4	25.3	36.6	3.1	-
26-27	62.0	62.0	7.9	-	4.4	12.4	49.6	3.1	-

Table 3-16: ComEd RPS Budget (\$)

DY	Shortfall from Previous DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend ²²⁹	Set Asides ²³⁰	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
21-22	-	158.8	158.8	223.6	0.4	21.2	245.1	(86.3)	67	67
22-23	(19.3)	160.2	140.9	154.5	0.3	11.2	166.0	(25.1)	-	-
23-24	(25.1)	161.5	136.4	147.7	0.3	11.3	159.3	(22.8)	-	-
24-25	(22.8)	161.8	139.0	130.9	0.3	11.2	142.4	(3.4)	-	-
25-26	(3.4)	161.7	158.3	63.5	0.2	21.2	84.9	73.4	-	-
26-27	-	162.0	162.0	25.5	-	11.2	36.7	125.3	-	-
27-28	-	162.7	162.7	21.8	-	11.3	33.1	129.6	-	-

²²⁷ Includes the balance of approved ABP Procurement, and the planned Fall 2020 or Spring 2021 Utility-Scale Wind Procurement.

²²⁸ See Table 3-18

²²⁹ Includes the balance of approved ABP Procurement, and the planned Fall 2020 or Spring 2021 Utility-Scale Wind Procurement.

²³⁰ See Table 3-18.

Table 3-17: MidAmerican RPS Budget (\$)

DY	Shortfall from Previous DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend ²³¹	Set Asides ²³²	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
21-22	-	0.6	0.6	0.7	-	0.0	0.8	(0.1)	-	-
22-23	(0.1)	0.6	0.5	0.6	-	0.0	0.6	(0.1)	-	-
23-24	(0.1)	0.6	0.5	0.6	-	0.0	0.6	(0.1)	-	-
24-25	(0.1)	0.6	0.5	0.6	-	0.0	0.6	(0.1)	-	-
25-26	(0.1)	0.6	0.6	0.3	-	0.0	0.4	0.2	-	-
26-27	-	0.6	0.6	0.1	-	0.0	0.1	0.5	-	-

Table 3-18: Statewide RPS Budget Set Asides (\$)

Delivery Year	Illinois Solar for All	Job Training (ComEd Budget)	Administrative Expenses (0.65% of Annual RPS Budget)	Total Set Asides
2021-22	11,171,068	10,000,000	4,468,427	25,639,495
2022-23	11,208,512		4,483,405	15,691,917
2023-24	11,260,386		4,504,154	15,764,540
2024-25	11,239,727		4,495,891	15,735,618
2025-26	11,214,691	10,000,000	4,485,876	25,700,567
2026-27	11,232,018		4,492,807	15,724,825

²³¹ Includes the balance of approved ABP Procurement, and the planned Fall 2019 or Spring 2021 Utility-Scale Wind Procurement.

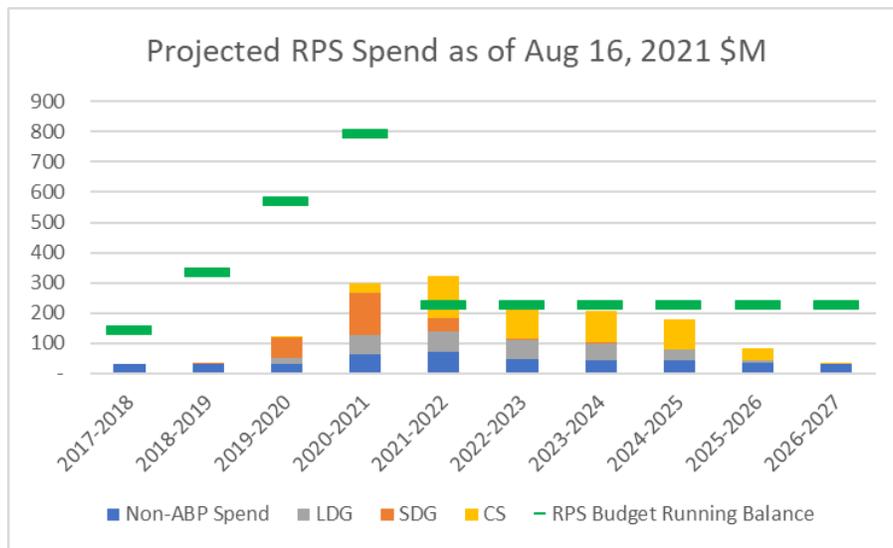
²³² See Table 3-18.

Table 3-19. Statewide RPS Budget (\$)

DY	Shortfall from Previous DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend ²³³	Set Asides ²³⁴	Total Expenditures	Remaining RPS Funds Balance at end of DY*	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
21-22	-	223,421,361	223,421,361	308,776,569	521,205	25,639,495	334,937,269	(111,515,908)	101,470,823	92,068,127
22-23	(19,447,781)	224,170,249	204,722,468	219,603,388	402,452	15,691,917	235,697,757	(30,975,289)	9,402,696	5,776,100
23-24	(25,199,190)	225,207,712	200,008,523	207,318,255	402,452	15,764,540	223,485,247	(23,476,725)	3,626,596	566,128
24-25	(22,910,596)	224,794,542	201,883,946	180,778,514	402,452	15,735,618	196,916,585	4,967,361	3,060,468	-
25-26	(3,480,293)	224,293,821	220,813,528	84,636,424	301,839	25,700,567	110,638,831	110,174,697	3,075,667	-
26-27	-	224,640,351	224,640,351	33,525,058	-	15,724,825	49,249,883	175,390,468	3,075,667	-

Figure 3-2 is a breakdown of spending by delivery year and expense category. This figure is updated from the similar figures provided in budget updates in December 2020, March 2021, and June 2021 (as discussed further in Section 3.23. below).

Figure 3-2: Projected RPS Spending (As of August 16, 2021)



²³³ Includes the balance of approved ABP Procurement, and the planned Fall 2019 or Spring 2021 Utility-Scale Wind Procurement.

²³⁴ See

Table 3-18.

3.18. Summary of REC Procurement Targets and RPS Budgets

The aggregation of REC Targets and RPS Budgets at a statewide level provides an important tool for planning and implementing the various procurements and programs under this Second Revised Plan. The table below presents a snapshot summary of the REC Gap and the RPS Fund Balance at the end of each delivery year based on current known expenditures under procurements and programs approved through the Initial and First Revised Plans, two essential factors to achieve the RPS Goals set forth by the Act.

For the negative balances listed in delivery years 2021-2023 through 2023-2024, Agency proposes a payment deferral mechanism as discussed in Section 3.24.3 below. The amounts listed as potential refunds to customers in the subsequent delivery years assume no additional procurements or opening of blocks for the Adjustable Block Program across those periods; the Agency has proposed certain additional procurements in Chapter 5 with REC deliveries commencing in the 2025-26 delivery year, and would likely be proposing additional procurements and program activity for these later delivery years as part of its next (Third Revised) Plan update.

Table 3-20: Statewide REC Gap and Available RPS Budget²³⁵

Delivery Year	REC Gap	RPS Funds Balance at end of DY estimated (\$) ²³⁶	Potential Refund to Customers (\$)
2021-22	16,783,881	(19,447,781)	-
2022-23	17,063,228	(25,199,190)	-
2023-24	18,992,191	(22,910,596)	-
2024-25	20,748,860	4,967,361	4,967,361
2025-26	22,489,329	110,174,697	110,174,697
2026-27	22,535,238	175,390,468	175,390,468

3.19. Alternative Compliance Payment Funds Held by the Utilities

As of August 16, 2021, Ameren Illinois held \$13,503,551 and ComEd held \$26,277,987.00 of alternative compliance payments collected from retail customers that took service under electric utilities' hourly pricing tariff or tariffs ("HACP"). These funds are in part committed to fund the REC purchases from the 2015 through 2017 Distributed Generation procurements conducted by the

²³⁵ This table does not account for RECs from the proposed utility-scale wind and brownfield site photovoltaic procurements discussed in Chapter 5. If successful, those procurements would feature projects that would deliver RECs during the later delivery years shown in this Table. Those deliveries would decrease the REC Gap and increase RPS expenditures, which would then decrease the RPS Funds Balance and potential refunds to customers. As these are competitive procurements not yet conducted, the budget impact is not known at this time.

²³⁶ Does not include ARES ACP funds collected by the utilities, or uncommitted Hourly ACP funds.

Agency, which featured five-year REC delivery contracts with payment upon delivery (and not prepayment).²³⁷ Under the ICC’s Order on Reopening in Docket No. 19-0995, REC delivery contracts resulting from those Distributed Generation procurements are not subject to payment deferral for the 2021-22 delivery year.

As of August 16, 2021, the remaining balance of uncommitted hourly alternative compliance payments—those not set aside to fund the Distributed Generation procurements—is \$13,503,551 for Ameren Illinois, and \$24,259,385.66 for ComEd.

Also, as of August 16, 2021, Ameren Illinois held \$23,519,406, ComEd held \$42,739,473, and MidAmerican held \$13,556 of alternative compliance payment funds collected from ARES since June 1, 2017 (“ARES ACP”)²³⁸ as shown in Table 3-22.

The Tables below summarize the balances of these Alternative Compliance Payments.

Table 3-21: Balance of HACP as of August 16, 2021 (\$)

Ameren	ComEd	MidAmerican
13,503,551	26,277,987.00	-

Table 3-22: Available ACPs (\$)

ACP	Ameren	ComEd	MidAmerican	All Utilities
Uncommitted HACP	13,503,551	24,259,385.66	-	37,762,909.66
ARES ACP	23,519,409	42,739,473	13,556	66,272,438
Total Available ACPs	37,022,960	66,998,858.66	13,556	104,035,374.66

In its filed Initial Plan, the IPA proposed to set aside the uncommitted balance of the Hourly ACP funds, as well as the ARES ACP funds collected by the utilities (a total of approximately \$100,000,000 as of April, 2020) for use at a later date in the event of a shortfall in the Available RPS Budgets, contemplating that the uncommitted funds could also be a source of the available funds used to help support the Illinois Solar for All Program. In its Order approving the Initial Plan, while the Commission agreed with the IPA that “spending ACP funds on RECs in the first four delivery years, while funds collected pursuant to Section 16-108(k) are unspent and refunded, would be contrary to the statutory intent of increasing the amount of renewable energy resources procured,” the Commission ultimately found that “the best use of these funds is to provide funding for new wind and new solar” and thus ACP funds should be used to fund “an additional forward procurement,” with funding for that procurement “prioritized such that any funds collected pursuant to Section 16-

²³⁷ 2016 and 2017 Distributed Generation procurements for MidAmerican were funded out of MidAmerican’s Renewable Energy Resources budget, as MidAmerican does not have any Hourly Alternative Compliance Payments.

²³⁸ Section 16-115D of the PUA provides that while “[t]hrough May 31, 2017, all alternative compliance payments by alternative retail electric suppliers shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund,” “beginning with the delivery year commencing June 1, 2017, all alternative compliance payments by alternative retail electric suppliers shall be remitted to the applicable electric utility” and not deposited into the RERF. (220 ILCS 5/16-115D(d)(4), (4.5).) See also 83 Ill Adm. Code Part 455. ComEd’s balance reflects interest earned on the ARES ACP funds held by ComEd, while Ameren Illinois’ and MidAmerican’s do not.

108(k) should be used prior to the ACP funds.”²³⁹ However, unlike the Adjustable Block Program, those procurements feature RECs paid upon delivery: meaning that such ACPs may not begin being spent until 2022 (when new utility scale projects begin REC deliveries) and could be tied up through 2037, frozen through being committed to funding those contract obligations when more urgent priorities exist which ACPs could help address.

In its First Revised Plan, the Agency proposed to revise how the utility-held ACPs should be utilized. With the end of the rollover period rapidly approaching, the Agency faced a potentially significant funding bottleneck starting in the 2021-2022 delivery year as unspent funds are returned to customers and RPS budgets begin being calculated only based on annual collections. Despite the Commission’s conclusion in Docket No. 17-0838 seeking to utilize ACPs for additional Forward Procurements,²⁴⁰ the Agency required more flexibility in its use of ACPs given the significant expected expenditures in coming years needed to fulfill the prepayment requirements of Adjustable Block Program contracts.

Consequently, for the First Revised Plan, the Agency proposed that the utility-held ACPs should be used in each delivery year after the use of funds collected pursuant to Section 16-108(k) for both Forward Procurements and the Adjustable Block Program, providing the Agency with a reserve balance of funds through which it can cover expenditures in excess of Section 16-108(k) collections. This approach is necessary to minimize payment deferrals in at least the 2021-2022 delivery year and possibly the two years directly thereafter, during which the Available Net RPS Budget is annually projected (as shown in Table 3-20) to be negative, meaning that absent this change to the use of utility-held ACPs, contractual expenditures would need to be pulled back (under curtailment clauses in the REC contracts) from what is now committed in order to bring the Available Net RPS Budget for the delivery year to zero. This approach to utilizing utility-held ACPs was approved by the Commission through approving the IPA’s First Revised Plan, and the IPA has maintained this approach for the Second Revised Plan.

3.20. Budget Uncertainty Due to Unknowns in Project Energization Timelines

One challenge the Agency has faced in understanding pending budget impacts is that project energization and REC deliveries—and thus resultant budget impacts²⁴¹—are not scheduled to begin at a fixed point. Instead, supported projects may become energized at any point over a period of time, whether immediately upon program application, closer to the contractual deadline for first deliveries, or later still due to extensions. This creates challenges into budget visibility in part because Adjustable Block Program projects carry large budget impacts upon energization (20% of contract value for distributed generation above 10 kW up to 2,000 kW (“Large DG”) and for community solar; 100% of contract value for distribution generation up to 10 kW (“Small DG”)), and because the ability to roll over prior years’ collections sunset with the conclusion of the 2020-21 delivery year. Assuming a project becomes energized during the 2021-22 delivery year (or even just that its first payment would occur in that year) carries very different budget consequences than if that project became energized in 2019-20, as in the latter scenario, previously collected Renewable Resources Budget

²³⁹ Docket No. 17-0838, Final Order dated April 3, 2018 at 8.

²⁴⁰ The additional forward procurements authorized in the Initial Plan are estimated to require \$35 million a year in funding assuming all projects are successfully energized.

²⁴¹ Under the Renewable Resources Budget reconciliation regime created by Section 16-108(k) of the PUA, the IPA understands that four-year reconciliation following the 2020-2021 delivery year, and the annual reconciliations after that, are based on anticipated cash inflows and outflows anticipated during a given delivery year.

funds could help meet first year payment obligations—including the large payment due upon energization.

Because payment only commences upon project energization, the Agency cannot have certainty about when funds for specific projects will begin to be spent. This dynamic has proven to be a significant challenge in modeling budgets for present and future delivery years. As indicated in Section 3.18, additional flexibility with the use of utility-held ACPs is required to mitigate budget uncertainty—although statutory changes allowing for extension of the 4-year rollover period or ensuring that funds could not be subject to reconciliation once committed by contract would be more helpful still.

As described extensively in Section 3.23 below, the COVID-19 global health pandemic has exacerbated the planning challenges resultant from budget impacts only being felt once projects reach energization. COVID-19 has introduced numerous supply chain and other development delays resulting in later energization timelines than originally forecast. These delays have pushed projected a higher-than-expected level REC delivery contract expenses forward in time, including tens of millions of dollars in expenses previously forecast for the 2020-2021 delivery year into the 2021-2022 delivery year. As Section 16-108(k) of the PUA limits funds collected for the first four years after P.A. 99-0906's effective date from being used to meet expenses incurred after May 31, 2021, this has left significantly less available funding to meet expected expenses than anticipated by the Agency in its Initial Plan or First Revised Plan.

As outlined by the IPA in its December 28, 2020 RPS Funding and Budget Update,²⁴² this situation has left available funds for the 2021-2022 delivery year (both available RPS budget plus ACPs) insufficient to meet projected expenses for the 2021-2022 delivery year on a statewide basis. To ensure that expenses do not exceed collections while minimizing disruption to Sellers under REC delivery contracts, the IPA petitioned to reopen Docket No. 19-0995 (approving the First Revised Plan) for the establishment of a payment deferral regime and authorization for the amendment of REC delivery contracts to implement payment deferrals. As discussed further in Section 3.23 below, the Commission approved the IPA's petition and key tenets of the Agency's proposed payment deferral approach.

Because the Commission's Order on Reopening in Docket No. 19-0995 only governs the 2021-2022 delivery year, this Second Revised Plan proposes an approach for handling projected RPS expenses exceeding collections for the delivery years thereafter. The IPA's proposed approach, which mirrors the approach taken through the ICC's Order on Reopening in Docket No. 19-0995, is also outlined in Section 3-23 below.

It must be underscored that this approach is merely the Agency's best attempt at triaging an untenable funding and payment structure. Legislative change is required to ensure that once REC delivery contracts are executed, funds collected to meet those contracts' expected expenditures cannot be subject to reconciliation, as the Agency simply cannot project with full confidence exactly when those expenditures will occur. A global health pandemic may be a rare event, but other risks to and delays in development timelines are not, including those occurring at no fault of a project developer.

²⁴² See:

[https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20\(28%20Dec%202020\).pdf](https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20(28%20Dec%202020).pdf)

If the Illinois RPS is intended to facilitate the development of new renewable energy projects that would not have existed but for state-administered support, and if that financial support is to only commence upon that project's successful development (which is an important safeguard against waste, fraud, and abuse), then the RPS's funding structure must allow for committed funds to be walled off from reconciliation even if not yet actually expended. Entities developing new renewable energy projects assume risk, and the purpose of supporting these development efforts through publicly-administered funds is to make that risk more bearable through the presence of at least some revenue certainty. Leaving that revenue uncertain, as happens by making available funds contingent on specific energization timelines, defeats the purpose of providing that support.

The IPA understands that implementing this approach of walling off committed funds from reconciliation requires changes in state law, and the Agency stands committed to assisting with facilitating those changes however possible. While legislative proposals introduced in the 102nd General Assembly seek to solve this issue, as of the time of the publishing of this draft Second Revised Plan, no such proposal has advanced through the General Assembly.

3.21. Budget Uncertainty Due to Annual Load Variations

The annual RPS Budget used in this Second Revised Plan is a function of the base-case load forecasts provided by the utilities and each utility's cost cap. These load forecasts are driven by a number of factors, which include but are not limited to weather, economics, demographics, assumed demand response and energy efficiency. Changes to any of the assumptions will result in actual load deviating from forecasted load. Examples include changes in weather patterns, changes in energy efficiency adoption rates, and changes to economic conditions. In practice, the annual RPS Budget for a delivery year will depend on the actual reference year load for each utility, which will likely deviate from the forecasted loads provided by the utilities—although in which direction that deviation will occur is impossible to know until that delivery year.

To see how deviations from the Base Case load forecasts may affect available RPS budgets, the IPA conducted a comparative analysis of the RPS Budget based on the Base Case, High Case, and Low Case. Load forecast data for Ameren Illinois and ComEd were used for this analysis. The RPS Budget for each utility, for each load case, is based on the product of the Applicable Load for a given year and the cost cap rate shown in Table 3-4.²⁴³ For each utility, the impact of the High Case and Low Case is the difference between the RPS budget for each case and the RPS Budget for the Base Case. The total is the sum of the differences for these utilities. The results are presented in Table 3-23.

²⁴³ The load data for the Base Case, High Case, and Low Case for Ameren and ComEd was provided by the utilities as part of their data submissions for this Second Revised Plan.

Table 3-23: Effect on RPS Budget of Annual Load Variations to the Utilities' Load Forecast

Delivery Year	Base Case Load Forecast [MWh]	Low Load Forecast [MWh]	Low Load Effect on RPS Budget [\$]	High Load Forecast [MWh]	High Load Effect on RPS Budget [\$]
2021-2022	119,390,384	116,580,643	(5,116,281)	123,731,182	8,012,582
2022-2023	119,768,939	116,900,337	(5,229,799)	124,021,326	7,847,506
2023-2024	120,310,678	116,925,396	(6,208,046)	124,031,904	6,843,551
2024-2025	120,073,928	116,464,016	(6,635,250)	123,515,383	6,316,578
2025-2026	119,800,325	116,467,348	(6,112,433)	123,499,591	6,805,342

As shown in Table 3-23 above, the impact of the low load forecast on the RPS Budget ranges from a reduction compared to the base case RPS Budgets of approximately \$5.1 million in delivery year 2021-2022 to a reduction of approximately \$6.1 million in delivery year 2025-2026. Alternatively, the impact of the high load forecast on the RPS Budget ranges from an increase compared to the base case RPS Budgets of approximately \$8 million in delivery year 2021-2022 to an increase of approximately \$6.8 million in delivery year 2025-2026. This constitutes a +/- 2 to 3.5% error band on annual RPS collections.

Because of the budget risk associated with load variability, the IPA recommends a cautious approach to making financial commitments such as the forward procurement of RECs and the expansion of ABP. The Agency notes that the scale of load forecast uncertainty increases the further out the forecasts are made, which is logical because factors such as economic indicators and climate/weather are compounded and inherently difficult to predict. That increasing uncertainty underscores the need for caution as the Agency considers the impact of procurements and programs on future year budgets.

3.22. Impact of RPS Budget on Procurement and Program Activities

The Agency's current projection of forecast Section 16-108(k) collections, accounting for the sunset in mid-2021 of the ability to roll over past collections to pay for future contractual deliveries and supplemented by utility-held ACPs, is insufficient to cover expected expenses in the 2021-2022 delivery year on a statewide basis. With reduced or missed payments deferred to the start of the next delivery year (which helps minimize adverse cash flow problems for Sellers under REC delivery contracts), this creates a cascading effect across the delivery years that follow.

Multiple factors could result in higher than expected revenues or lower than expected expenses, including one or more of the following: First, future changes in utility load forecasts could demonstrate greater than expected retail sales of electricity, thus resulting in additional RPS budget funds. Second, community solar projects could seek reduced levels of small subscribers than presently expected, thus resulting in lower REC prices applicable to those systems. Third, some community solar projects could achieve less than complete subscribership of their physical capacity.

Fourth, additional projects presently under contract could fail to be developed, freeing up additional budget capacity.²⁴⁴ However, given the current gulf between available funds and projected expenses, changes in these factors are unlikely to result in sufficient budget availability to support near-term new RPS program or procurement activity.

Fifth, and most importantly, legislative changes could extend the budget rollover's sunset period, thus freeing up funds collected under Section 16-108(k) tariffs but not spent by May 31, 2021 for future REC procurement rather than having those funds refunded to ratepayers—or otherwise ensure that funds committed by REC delivery contracts are not subject to reconciliation. Should this happen, the Agency understands that such changes would most likely happen through omnibus energy legislation which may necessitate an overhaul of this planning process. In that case, the Agency would likely be developing a new and different plan designed to comply with those changes in state law—and that new and different plan would address proposals for additional program and procurement activity.

Since the publishing of its Final First Revised Plan, has been biannually reviewing updated utility load forecast information and new/existing contract obligation/payment information to determine expected RPS budget availability, and published the resulting updated budget forecasts on its website.²⁴⁵ As previously committed to through the First Revised Plan, the Agency will in all cases seek to have under contract projects with likely annual expenditures equaling no more than 95% of expected available funds for any given delivery year to guard against the potential payment reduction of existing contracts.

Should sufficient additional RPS funding somehow become available without requiring the development of an entirely new renewable resources procurement Plan, the Agency proposes utilize the following contingency approach addressing which programs and procurements it will prioritize supporting, borrowing largely from determinations made in Docket No. 19-0995.²⁴⁶ That approach is as follows:

First, any additional funding not accounted for in the tables above would be utilized first and foremost to ensure that existing REC delivery holder payment deferrals are minimized to the greatest extent possible or eliminated altogether, including by ensuring minimized reliance on alternative compliance payments to meet REC delivery contract expenses for the 2021-22 delivery year.

Second, the Agency shall conduct a competitive procurement for up to 500,000 RECs delivered annually from utility-scale solar and/or wind projects.²⁴⁷

Third, should the additional/unexpected funding become available after a utility-scale procurement event noted above, the Agency would next look to conduct an additional brownfield site photovoltaic project competitive procurement (“brownfield procurement”) with a target quantity of 50,000 RECs

²⁴⁴ Reductions in payment obligations to a community solar or a Large DG project within the ABP would have a ripple effect across the projected RPS expenditures in each of five sequential delivery years, due to the statutory payment schedule that compensates such a project for its RECs ratably over four years (further refined as seventeen quarterly payments by the initial ABP REC Contract). For example, a project that is expected to receive its first REC payment in September 2020, within the 2020-2021 delivery year, would receive its final payment in September 2024, within the 2024-2025 delivery year.

²⁴⁵ See:

[https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20\(28%20Dec%202020\).pdf](https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20(28%20Dec%202020).pdf) and [https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20\(11%20June%202021\).pdf](https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20(11%20June%202021).pdf).

²⁴⁶ See Docket 19-0995, Final Order dated February 18, 2020 at 19-20.

²⁴⁷ Id. at 20.

delivered annually. The Commission agreed that this is a prudent manner by which to provide ongoing support for a market segment that was offered robust narrative support in the declaratory passages of Public Act 99-0906, but with a relatively small minimum target (only 2% of new photovoltaic project RECs).²⁴⁸

Fourth, should funding be available after the above-mentioned procurement events, the Agency will open additional blocks of capacity for the Adjustable Block Program to accommodate whatever funds are available, up to the number of RECs needed to reach a total of 1,500,000 annually delivered RECs from the Adjustable Block Program (the 2025 Delivery Year target quantity found in Section 1-75(c)(1)(C) of the Act, as it is 50% of 3,000,000 annual REC deliveries).²⁴⁹ The Commission agreed that smaller block sizes than those specified in Section 6.3.1 may be advisable and deferred to the IPA's determination at the time the opportunity presents.²⁵⁰ Under the Commission's Order, the Agency shall not procure more than the 2025 Delivery Year Adjustable Block Program statutory target of 1.5 million RECs delivered annually under this contingency plan.²⁵¹

Notwithstanding the revised contingency plan described above, pursuant to the Commission's Final Order in Docket No. 19-0995 approving the First Revised Plan, the Agency must ensure that a minimum of 1,000,000 RECs delivered annually from the Adjustable Block Program be maintained at all times. Based on contracts executed to date and existing waitlist capacity, the Agency does not perceive this to be a risk.

3.23. Spring 2021 RPS Budget Update and Proposed Payment Deferral Regime

3.23.1. Introduction

This text has been largely maintained from the IPA's June 7, 2021 Final First Revised Plan on Reopening to memorialize treatment of REC delivery contracts for the 2021-2022 delivery year, also reflected in the Commission's May 27, 2021 Order on Reopening in Docket No. 19-0995. Treatment of REC delivery contracts for the 2022-2023 and 2023-2024 delivery year in the instance of budget insufficiency is addressed in a new Section 3.24 below.

As described in Section 3.20, delays in project energization – and thus delays in REC delivery contract payouts, as renewable energy projects are not eligible for payment until energized – pull initial RPS budget impacts forward into chronologically later periods than previously forecast, and in many cases, into later delivery years. For Adjustable Block Program contracts in particular, because payments are front-loaded (100% due upon energization for Small Distributed Generation projects; 20% due upon energization for Large Distributed Generation projects and community solar projects, with the balance ratably paid out over the following four years), those initial payments made upon energization carry outsized RPS budget impacts. As expenses that had been expected to be incurred in the 2020-21 delivery year are pulled forward into the 2021-22 delivery year, this creates the following challenge: because Section 16-108(k) of the Public Utilities Act restricts the ability to utilize the first four years of RPS collections after the enactment of P.A. 99-0906 (the 2017-18 through 2020-21 delivery years) to meet RPS expenses beginning with the 2021-22 delivery year, expenses

²⁴⁸ Id.

²⁴⁹ Id.

²⁵⁰ Id.

²⁵¹ Id.

associated with that upcoming delivery year have a significantly lower budget of available funds than expenses associated with prior delivery years.

The Illinois Power Agency filed its Revised Long-Term Renewable Resources Procurement with the Illinois Commerce Commission in October 2019. Tables included in Chapter 3 of that filed Revised Plan demonstrated sufficient budget availability (through both collections pursuant to Section 16-108(k) and alternative compliance payments held by the utilities) to meet expected RPS expenditures based on the arc of projected expenditures as understood at that time. Because that analysis showed *sufficient* funding, no proposal was made for how Buyers under REC delivery contracts (ComEd, Ameren Illinois, and MidAmerican) should handle payment deferrals in the case of *insufficient* funding. That Revised Plan was approved by the ICC in Docket No. 19-0995 on February 18, 2020, with instruction that the IPA file a Final Revised Plan modified for consistency with the Commission's Order in that proceeding within 60 days.

During that 60-day period, the COVID-19 global health pandemic began to take grip in the United States. Assemblies and public activities began being restricted in mid-March 2020, and the IPA issued its initial COVID-19 guidance on March 20, 2020.²⁵² As the IPA considered the content of its Final Revised Plan, the Agency determined that some assessment of the COVID-19 pandemic's potential impacts on RPS activities warranted discussion in that filing.

Section 3.20.1 of the Final First Revised Long-Term Renewable Resources Procurement Plan filed by the Agency in Docket No. 19-0995 on April 20, 2020 offered early insights into the potential effects of the COVID-19 pandemic on project energization timelines. Specifically, that section offered estimates for potential RPS budget impacts resultant from COVID-19 possibly delaying project energization timelines. Under the "slow energization" scenarios described in Table 3-24 as Part of Section 3.20.1, the RPS budget was projected to face shortfalls – i.e., insufficient collections plus alternative compliance payments to meet projected expenses – in the 2021-22 delivery year. Of course, any assessment made in April 2020 about the longer-term impacts of the COVID-19 pandemic carried massive uncertainty, and because Adjustable Block Program REC delivery contracts only began being approved by the Illinois Commerce Commission in April 2019, Approved Vendors had not yet begun offering energization deadline extension requests at volumes that provided meaningful insight into the effects of COVID-19 on new renewable energy project development timelines.²⁵³ Thus, while concerns at that time were certainly genuine, those concerns were still mostly theoretical.

Since April 2020, over 1,200 energization deadline extension requests have been received and processed in connection with Adjustable Block Program projects. As discussed below, and as taken from narratives supporting the many extension requests provided by Approved Vendors to the

²⁵² [https://www2.illinois.gov/sites/ipa/Documents/IPA%20COVID-19%20ANNOUNCEMENT%20\(20%20March%202020%20330pm\).pdf](https://www2.illinois.gov/sites/ipa/Documents/IPA%20COVID-19%20ANNOUNCEMENT%20(20%20March%202020%20330pm).pdf)

²⁵³ As described in Section 6.15.1, distributed generation projects are allowed 12 months from Commission approval (the REC delivery contract's "Trade Date") to achieve energization, while community solar projects are allowed 18 months. Thus, for example, a 1 MW distributed generation project with a contract approved by the Commission in July 2019 would have a July 2020 energization deadline, while a community solar project with a July 2019 Commission approval date would have a December 2020 energization deadline. Extensions to that deadline may be obtained as a matter of right through payment of additional collateral, or available at the discretion of the counterparty utility or the IPA for specified reasons (including permitting delays, good cause, etc.). As extension requests are often made by Approved Vendors in the weeks or days directly preceding a project's energization deadline, those requests have been received and granted on a rolling basis through 2020 and into 2021.

Agency, multiple factors directly resulting from the COVID-19 global pandemic have caused unforeseen delays in the development timeline for hundreds of ABP projects.

As is now well known, supply chains across the globe were halted or severely impacted by COVID-19 during the onset of the pandemic in early 2020, with some of those impacts continuing today. Many Approved Vendors seeking extensions for their projects had no way to plan for this type of massive supply chain disruption that kept various components necessary to the construction of a solar PV project in limbo across the globe. As any type of construction benefits from economies of scale, large component orders that impacted numerous projects slated for construction in Illinois in 2020 were delayed due to this global slow-down in shipping and receiving. Approved Vendors that expected to receive system parts such as panels, inverters, racking support, etc. in order to commence construction were often left to wait due to this unprecedented halt of large procurements of all sorts across the globe.

Additionally, lack of readily available labor was cited by Approved Vendors as a cause of project development delay brought on by the pandemic. Approved Vendors communicated that the number of available laborers declined, thus making construction planning difficult to impossible. Ongoing uncertainty in the amount of labor that would be available to support the development of projects caused many Approved Vendors to experience unanticipated delays in construction timelines that persist today as the pandemic conditions continue.

Another unexpected issue faced by Approved Vendors is that projects planned for construction on various schools across the state were delayed both by the inability for school district boards to meet due to safety measures in place to curb the spread of the virus, as well as construction being limited to only summer months. COVID-19 related delays ensured that construction for projects slated for schools during summer 2020 would not be possible, pushing construction timelines for these types of projects to the summer months of 2021.

While many of the issues described above could independently cause a major delay in a project's development timeline, many Approved Vendors that sought an extension experienced multiple issues related to COVID-19 that negatively impacted project development. Numerous projects faced not only a solitary set of issues related to supply-chain delays, inability to visit the project site, or a shortage of available labor required to construct a project, but for many projects all of these issues coalesced to push the development timeline back even further than originally contemplated to create the need for at least one and in several instances two energization deadline extension requests.

Notably, of the 112 community solar projects featuring REC delivery contracts through the Adjustable Block Program, as of March 2021, energization deadline extension requests have been received for 109 projects. While not its only cause, examining the budget impacts of this community solar project energization delay phenomenon is particularly helpful for illustrating the current RPS budget crisis: because the first REC delivery contract payment for a community solar project can be large and lumpy – up to \$1.2 million in standalone value, if the project received a Block 1 award and has achieved maximum small subscriber status – shifting 50 such payments from the 2020-21 delivery year to the 2021-22 delivery year results in at least \$60 million in expenses moving across those delivery years (and possibly more, should any additional quarterly payments also be shifted out across delivery years). A similar phenomenon has occurred with distributed generation projects: as of March 2021, while approximately 20% of all Large DG projects have requested extensions, for projects over 100 kW in size, over 50% have requested extensions. For projects larger than 500 kW,

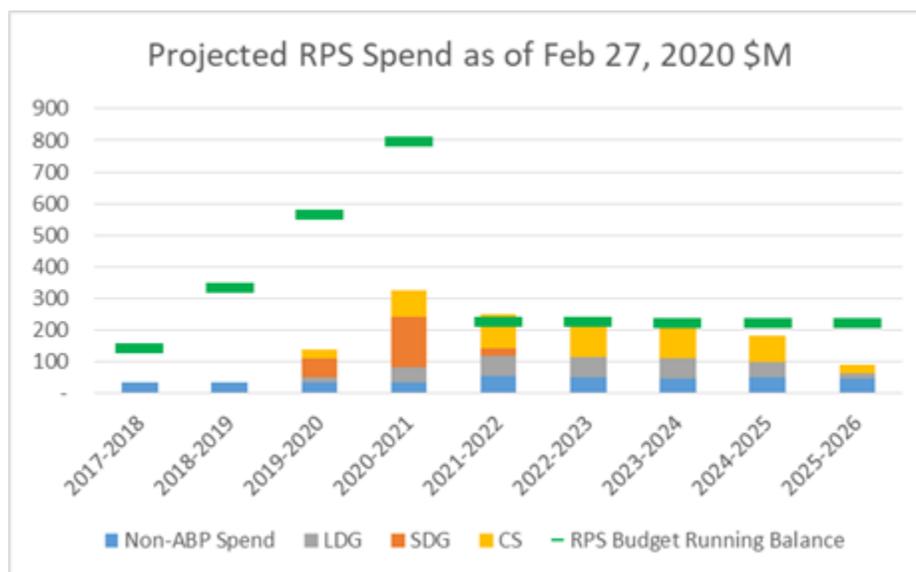
over 70% have requested extensions. Because larger systems have more expensive REC delivery contracts (as more RECs will be delivered from these projects), extensions for these larger projects have an outsized impact on RPS budget projections.

3.23.2. December 28, 2020 budget release

As outlined in Section 3.22, the Agency has committed to biannually reviewing updated utility load forecast information, as well as contract obligation and payment information, to determine expected RPS budget availability. The Agency’s first effort at a biannual review came in late 2020. By that time, the impacts of the COVID-19 pandemic on project energization deadlines had become more apparent, and energization deadline extension requests received by the Agency provided important new data points to be folded into RPS budget modeling.

The IPA released this first biannual RPS Budget and Funding Update on December 28, 2020.²⁵⁴ The update confirmed that what was viewed as a theoretical outcome of the COVID-19 pandemic in April 2020 was now very real: similar to the Final Plan’s April 2020 slow energization scenario, the Agency’s December 2020 modeling showed that, absent legislative action extending the rollover period, the statewide RPS budget (inclusive of available alternative compliance payments) would face an expected estimated shortfall of approximate \$67 million in the 2021-22 delivery year. The release likewise estimated that over \$180 million in expenses that the IPA had previously projected would occur within the first four delivery years were now projected to occur in the 2021-22 delivery year and beyond, creating significant budget constraints in those upcoming years given the current inability to utilize prior years’ collections for meeting those expenses.²⁵⁵ The following charts included in that update provide a useful illustration of that phenomenon:

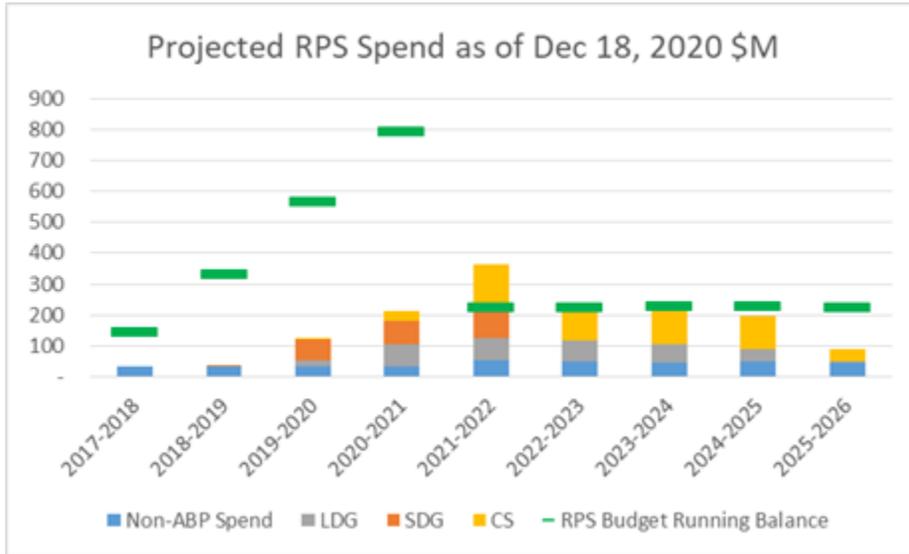
Figure 3-3: Projected RPS Spending (Based on April 20, 2020 Long-Term Plan)



²⁵⁴ The IPA’s December 28, 2020 RPS Funding and Budget Update can be found here: [https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20\(28%20Dec%202020\).pdf](https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20(28%20Dec%202020).pdf).

²⁵⁵ This difference is apparent through reviewing the amount potentially subject to reconciliation in the Agency’s December 2020 RPS budget analysis (\$381 million) versus the amount previously modeled as subject to reconciliation (\$196 million).

Figure 3-4: Projected RPS Spending (Based on December 18, 2020 Update)



As demonstrated in Scenarios 4 and 5 found in Table 3-24 of the First Revised Plan, a statutory revision extending the rollover period forward would eliminate this risk of a shortfall. While a two-year rollover extension was modeled in Table 3-24, even a one-year extension of the rollover sunset date would eliminate shortfall risk: as 2021-22 delivery year expenses could be met wholly through prior years’ RPS collections under a one-year rollover extension, alternative compliance payments no longer drawn down in the 2021-22 delivery year would then serve as a robust reserve fund sufficient to cover much smaller expected shortfalls in the 2022-23 and 2023-24 delivery years.

During the “lame duck” session of the 101st General Assembly (from January 8, 2021 through January 13, 2021), legislation was introduced which would have extended the rollover sunset date by two years while directing the Agency to conduct new program and procurement activities.²⁵⁶ That bill failed to receive a floor vote. Legislation focused solely on solving this pending shortfall conundrum was introduced in the 102nd General Assembly,²⁵⁷ as well as several larger energy bills, each of which failed to receive floor votes.

3.23.3. March 3, 2021 Budget Update

In developing its March 2021 filing to reopen Docket No. 19-0995, the IPA prepared updated versions of the tables contained in its December 28, 2020 release. While less than three months passed between the December release, these updated tables contained useful new information for RPS budget modeling, as both Adjustable Block Program contracts and utility-counterparty Illinois Solar for All contracts feature quarterly invoicing for all activities up through a certain date. Because

²⁵⁶ This legislation was offered through amendments to then-SB 3096; see: <https://www.ilga.gov/legislation/BillStatus.asp?DocNum=3096&GAID=15&DocTypeID=SB&LegId=124415&SessionID=108&GA=101>.

²⁵⁷ See HB 3822: <https://www.ilga.gov/legislation/BillStatus.asp?DocNum=3822&GAID=16&DocTypeID=HB&LegId=132890&SessionID=110&GA=102> and SB 2433: <https://www.ilga.gov/legislation/BillStatus.asp?GA=102&DocTypeID=SB&DocNum=2433&GAID=16&SessionID=110&LegID=135087>.

February 28, 2021 constituted the close of the third quarterly invoicing period for the 2020-21 delivery year, the IPA was able to utilize information about projects verified as energized through that date (and thus subject to a March 2021 invoicing window) in estimating the arc of budget impacts extending from individual projects.

While useful and important, one quarterly period's worth of new information was unlikely to significantly change the overall RPS budget picture, and it generally did not. For example, the expected amount subject to reconciliation at the end of Delivery Year 2020-2021 declined from \$381 million to \$352 million, the expected 2021-2022 budget shortfall (after accounting for use of alternative compliance payments) for Ameren Illinois declined from \$8.4 million to \$2.2 million, the expected budget shortfall for ComEd declined from \$58.6 million to \$49.5 million, and the expected budget shortfall for MidAmerican remained unchanged. The key driver of these reductions was the accelerated energization of ABP projects relative to prior projections. As discussed further in new Section 3.24, proposed shortfalls once again declined in the IPA's June 12, 2021 RPS budget update.

Budget projections carry uncertainty; a new project may currently be projected to become energized in, say, the first quarter of 2021-22 (and thus would be modeled as having four quarterly payments associated with the 2021-22 delivery year), but in reality, it may not be energized until the final quarter of that year—meaning that project's actual budget impacts for the 2021-22 delivery year would be less than modeled. As discussed further below, because these expected budget impacts can only be estimated with certainty when actual energization dates are known, this creates significant planning challenges in determining how to maximize available RPS funding while implementing payment deferrals required to keep expenses below Section 1-75(c)(1)(E)'s statutory cap.

But those differences due to uncertainty cannot change the following bottom-line takeaway: expenses are virtually certain to exceed collections plus alternative compliance payments for the 2021-22 delivery year, and by a non-trivial amount.²⁵⁸ As the Agency is unaware of any way in which the Commission, the IPA, or the utilities themselves could legally authorize additional funds to meet these expenses, maintaining the integrity of Section 1-75(c)(1)(E)'s rate impact cap requires that a regime be administratively authorized providing parties with clarity and certainty around how payment deferrals should be implemented. And as discussed further below, the RPS expenses are of various stripes, creating questions about which expected expenses, if any, should be considered senior to (or otherwise higher-priority than) others.

The Agency petitioned the Commission to reopen Docket No. 19-0995, the Illinois Commerce Commission's docketed proceeding for approval of the IPA's Revised Long-Term Renewable Resources Procurement Plan intended to govern RPS program, procurement, and payment activity for the upcoming 2021-22 delivery year, to incorporate these changed budget assumptions and to propose a path forward for resultant payment deferrals. On May 27, 2021, the Commission approved the Agency's proposed modifications to the First Revised Plan intended to address this issue, thus providing much-needed clarity and certainty to all affected parties.

²⁵⁸ While smaller shortfalls are also shown for the 2022-23 and 2023-24 delivery years, the approach for handling those shortfalls is addressed through Section 3.24 of this draft Second Revised Plan.

3.23.4. Precedent for Payment Deferrals: the 2010 LTPPAs

Prior to the Order on Reopening in ICC Docket No. 19-0995, the Commission had previously authorized a regime governing reductions in payments to REC delivery contracts in the case that available RPS funding was projected as insufficient to meet expected expenditures.

Pursuant to the IPA's Commission-approved 2009 Procurement Plan, the Agency solicited bids in 2010 for long-term power purchase agreements (LTPPAs) to procure renewable resources. The Commission authorized the IPA to procure up to two million MWhs of renewable energy, along with the associated RECs, on an annual basis for a term of twenty years. This amount, based upon load forecasts made in 2009, represented less than 4% of the IPA's total expected energy requirement in the 2012 planning period. The total 40 million MWhs of renewable energy purchased through the LTPPAs over their twenty-year lives was to be divided as follows: 600,000 MWhs each year for 20 years for the Ameren service territory and 1,400,000 MWhs each year for 20 years for the ComEd service territory. The utilities were authorized to recover all reasonable and prudent costs associated with the purchase of the annual energy and RECs specified in the LTPPAs through ICC-approved tariffs. The LTPPA contracts specify that the utilities shall not be liable under the agreements for any costs that cannot be recovered from customers through those approved pass-through tariffs.

Subsequent to the 2010 LTPPA procurement, the retail supply market in Illinois grew more quickly than anticipated, in part due to the early success of municipal aggregation programs. The resulting shift in significant loads of eligible retail customers from the utilities to alternative suppliers in turn reduced revenues collected under the utilities' pass-through tariffs. A statutory rate impact cap under Section 1-75(c)(2) of the IPA Act limited the utilities' ability to recover the revenues at the amount forecasted when the 2009 Procurement Plan was developed.

By the time the IPA filed its 2013 Procurement Plan in September of 2012, it was clear that the statutory rate cap would reduce the budget significantly, such that curtailment of LTPPAs was required. The IPA indicated in the proposed 2013 Plan that purchases under the LTPPAs would need to be reduced, but the Agency was uncertain at the time of the 2013 Plan filing by how much the contracts must be reduced. Procedures in the contracts themselves dictated the method through which a utility must seek Commission approval in order to declare a curtailment event, and in approving the 2013 Plan, the ICC made a determination that curtailment of the LTPPAs was necessary and appropriate.²⁵⁹ The Commission further found that the LTPPAs should be curtailed upon a pro-rata basis and required the Plan to be amended to state that any reductions in the agreements should be applied proportionately to the LTPPAs consistent with the terms of the contracts.²⁶⁰ Additionally, the Commission found that alternative compliance payment funds (ACPs) collected by the ComEd from their hourly priced customers shall be used to help mitigate the need to reduce the LTPPAs.²⁶¹

While useful precedent procedurally, that situation features key substantive dissimilarities with the current situation. First, the 2010 LTPPAs were a single contract structure. By contrast, current RPS expenses are made up of a variety of different contract types, including payment structures that, by law, vary by project type. Second, expected expenses for the 2010 LTPPAs were generally predictable: prices were known, and overall payments were reflective of a facility's REC deliveries.

²⁵⁹ See Docket No. 12-0544, Final Order dated December 19, 2012 at 110.

²⁶⁰ See *id.*

²⁶¹ See *id.* at 111.

Conversely, in the current situation, RPS expenses in the upcoming delivery year are expected to vary by, for instance, the level of subscribed shares for a community solar project and whether that project has met small subscriber adder thresholds. And with certain systems' payments frontloaded upon energization, not having perfect visibility into energization timelines means not having perfect visibility into when expenses associated with certain projects will begin to be felt. And lastly, unlike with the 2010 LTPPAs, there is no additional reserve fund available for mitigation—in the present case, the budget deficit at issue exists at the levels posited above *only after* the existing balance of alternative compliance payments is already exhausted.

3.23.5. Current RPS expenditure categories

Before outlining a regime for how expenses could be reduced to meet available budgets, a discussion of exactly what expenses are paid through the RPS budget may be helpful. Below is an outline of expenses projected to be paid through the RPS budget (i.e., collections under Section 16-108(k) of the Public Utilities Act and available alternative compliance payments), as well as estimated budget impacts associated with each for the 2021-22 delivery year in parentheses.²⁶²

2010 Long-Term Power Purchase Agreements (est. \$24.1M)

Bundled REC + energy contracts entered into in 2010 to facilitate the development of new utility-scale renewable energy generation (primarily large wind farms); only the REC portion of the expense (the imputed REC price) is calculated as a drawdown from the RPS budget, with the energy price embedded into the rate paid by default supply customers.

2016-17 Utility Distributed Generation Procurements (est. \$2.5M)

Procurements conducted under authority from the ICC's approval of the IPA's 2015, 2016, and 2017 annual energy procurement plans to support new distributed generation project development under the RPS pre-P.A. 99-0906. These procurements resulted in 5-year REC delivery contracts primarily utilizing alternative compliance payments collected from hourly customers, with final payments expected to be made in the 2022-23 delivery year.

Initial Forward Procurements (utility-scale wind, utility-scale solar) (est. \$9.2M)

Authorized by Section 1-75(c)(1)(G)(i)-(ii) of the IPA Act, these procurements were intended to support the development of new utility-scale wind and solar projects prior to the Commission's authorization of the IPA's Long-Term Renewable Resources Procurement Plan through 15-year REC delivery contracts paid upon REC deliveries being actually made and invoiced monthly.

Unlike the other forward procurements discussed below, these carry a statutory deadline for first REC deliveries, although that deadline has already once been extended by the General Assembly.

Other Forward Procurements (utility-scale wind, utility-scale solar, brownfield site photovoltaics) (est. \$18.8M)

Authorized primarily by the ICC's Order approving the IPA's Original Long-Term Renewable Resources Procurement Plan in Docket No. 17-0838, these procurements were intended to support the development of new utility-scale wind and solar projects, and new brownfield site photovoltaic

²⁶² As demonstrated in prior tables, both budgets and expenses vary by utility; as the IPA believes a uniform solution is warranted, statewide budget impacts are presented.

projects, to meet future years' Section 1-75(c)(1)(C) new project REC delivery targets. As with the initial forward procurements, these procurements feature 15-year REC delivery contracts with payments made upon delivery (and thus, once energized, the 2021-22 budget impact of these procurements will be approximately 1/15th of the overall contract amount).

ABP: Small Distributed Generation (est. \$82.1M)

Small distributed generation photovoltaic projects (10 kW in size and below – generally residential) are supported through the Adjustable Block Program via 15-year REC delivery contracts with full up-front payment upon energization. Blocks for small distributed generation closed in December of 2020 (meaning no new project applications were promised REC delivery contracts after that date);²⁶³ while those projects are allowed 12 months from ICC contract approval to become energized (and some are still under program administrator review), development timelines are generally shorter for smaller projects.

ABP: Large Distributed Generation (est. \$69.3M)

Large distributed generation photovoltaic projects (over 10 kW to 2 MW in size) are likewise given 12 months to become energized, but generally take longer to become energized given the complexity inherent in larger scale project development and feature higher rates of energization deadline extension requests than Small DG systems. Large DG blocks closed in March 2020, but certain project types – especially schools or other projects involving public-sector commitments – may be more acutely impacted by COVID-related delays.

The payment structure in the 15-year REC delivery contracts for Large DG are likewise frontloaded, but less so than with Small DG; these projects are paid 20% of full contract value upon energization, with remaining payments made ratably on a quarterly basis over the subsequent 4-year period.

ABP: Community Solar (est. \$141.4M)

Given that community solar projects must also acquire subscribers, community solar projects are provided 18 months to become energized, with REC payments tied to the projects level of subscribed shares. The project's level of small subscriber participation may also impact REC delivery contract payments: as described in Section 6.15.4, reaching threshold of small subscriber participation increases the applicable REC price. RPS budget modeling assumes that community solar projects are a) fully subscribed and b) able to reach the highest available threshold of small subscriber participation (and thus will feature the largest possible RPS budget impacts); from the IPA's anecdotal observation and discussions with Approved Vendors, this assumption is likely a reasonable expectation.

As outlined above, 109 out of 112 community solar projects have requested extensions to energization deadlines; the Agency has surveyed community solar project developers for information about expected actual energization dates for each of their contracted projects, and results from those surveys were incorporated into RPS budget modeling assumptions.

Illinois Solar for All: Utility-counterparty REC delivery contracts (est. \$11M)

²⁶³ Projects applications received after block closure are waitlisted based on application date and may be selected off the waitlist should a selected project withdraw or fail to be successfully developed.

While the Illinois Solar for All Program is funded primarily through funding in the state-administered Renewable Energy Resources Fund, Section 1-75(c)(1)(O) of the IPA Act also dedicates “5% of the funds available under the plan for the applicable delivery year, or \$10,000,000 per delivery year, whichever is greater” to fund Illinois Solar for All. While this delivery year allocation is expected to be just over \$11 million in 2021-22 (and thus this amount would support the 2021-22 program year budget), the amounts subject to payment in 2021-22 may be different, and depend on energization timelines for projects approved in prior program years.

For budget modeling purposes, the IPA has assumed that a single program year’s budget of projects will be energized in the upcoming delivery year, resulting in a placeholder value of \$11 million in RPS budget modeling. However, based on the portfolio of projects under utility contracts and revised energization dates applicable to those projects (specifically, accounting for delays experienced by earlier-approved projects), \$15 million may be a “high-case” estimate for 2021-22 delivery year budget impacts, and the actual amount could vary considerably.²⁶⁴

Illinois Solar for All: Job Training Funds (\$10M)

Also pursuant to Section 1-75(c)(1)(O) of the IPA Act, once every four years (with the 2021-22 delivery year being one such year) \$10 million from ComEd’s RPS budget is due to be allocated to job training programs authorized under Section 16-108.12 of the Public Utilities Act. As with ILSFA program year expenses, RPS budget modeling generally assumes that this allocation will continue to be made.

Administrative Costs (est. \$4.4M)

Projected administrative costs for the 2021-2022 delivery year are estimated to be about \$4.4M, which is equivalent to 2% of the Annual RPS Budget. Projected administrative costs are allocated as follows: \$4M for Consultant Costs (\$3.6M for the Adjustable Block Program Administrator, \$0.25M for the Procurement Planning Consultant, and \$0.2M for the Procurement Administrator), and \$0.4M for REC retirement fees. This amount is also subject to variance.

3.23.6. Key considerations in implementing a deferral regime

In working through a proposed approach for a reduction in expenses to meet available funds, the IPA believes certain considerations should be highlighted (even if not necessarily resulting in an approach to accommodate that consideration).

Statutory considerations

At least two statutory clauses could be interpreted to prioritize to certain RPS expenses over others for purposes of payment deferrals. First, Section 1-75(c)(1)(F) of the IPA Act directs that if application of the rate impact cap prevents the IPA from meeting RPS goals, then the Long-Term Plan shall prioritize compliance with RPS requirements “regarding renewable energy credits” in the following order:

- (i) renewable energy credits under existing contractual obligations;

²⁶⁴ Regardless of size or project type, Illinois Solar for All projects are paid out on energization in a manner similar to Adjustable Block Program Small DG projects. Therefore, the full budget impact of Illinois Solar for All project completions will be felt in the program year the project is energized.

- (i-5) funding for the Illinois Solar for All Program, as described in subparagraph (O) of this paragraph (1);
- (ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1); and
- (iii) renewable energy credits necessary to meet the remaining requirements of this subsection (c).

It is not clear exactly what guidance this language offers for the present context. The present RPS budget crisis generally concerns *not* prospective additional program or procurement activity, but instead funding availability for a wide range of what are already existing contractual obligations. Prioritizing all contracts already executed would perhaps eliminate the approximately \$21 million in prospective 2021-22 delivery year expenses for the Illinois Solar for All Program under Section 1-75(c)(1)(O), but doing so would a) still result in a significant shortfall, b) elevate Adjustable Block Program and utility-scale procurement obligations above the Illinois Solar for All obligations (which could be interpreted as inconsistent with the ordering between (i-5) and (ii), above), and c) do little to control expenses for Illinois Solar for All contracts already executed.

Another possible interpretation is that “existing contractual obligations” refers only to those obligations already in existence as of the effective date of Public Act 99-0906, which would exempt the LTPPAs and utility DG procurement contracts from payment deferrals. Were that the General Assembly’s intent, however, one may expect (i) to specifically refer to “existing contractual obligations as of the date of this Amendatory Act” or otherwise feature scope-limiting text. Similarly, the prioritization of (i-5) expenses above could be read to prioritize existing Illinois Solar for All contract expenses above existing utility-scale and Adjustable Block Program expenses, as the latter were contracts executed in an effort to meet a lower priority item under 1-75(c)(1)(F) (new wind and new photovoltaic procurement requirements).

Second, Section 1-75(c)(1)(O)’s allocation to Illinois Solar for All is written as follows:

For the delivery year beginning June 1, 2018, the long-term renewable resources procurement plan required by this subsection (c) shall provide for the Agency to procure contracts to continue offering the Illinois Solar for All Program described in subsection (b) of Section 1-56 of this Act, and the contracts approved by the Commission shall be executed by the utilities that are subject to this subsection (c). The long-term renewable resources procurement plan shall allocate 5% of the funds available under the plan for the applicable delivery year, or \$10,000,000 per delivery year, whichever is greater, to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or \$20,000,000 per delivery year, whichever is greater, and \$10,000,000 of such funds in such year shall be used by an electric utility that serves more than 3,000,000 retail customers in the State to implement a Commission-approved plan under Section 16-108.12 of the Public Utilities Act. In making the determinations required under this subparagraph (O), the Commission shall consider the experience and performance under the programs and any evaluation reports. The

Commission shall also provide for an independent evaluation of those programs on a periodic basis that are funded under this subparagraph (O).

One could interpret this prescriptive allocation as demanding program year allocations for Illinois Solar for All be backed out of the RPS budget before determining the budget available to meet other obligations, especially when read in conjunction with the (i-5) prioritization of Illinois Solar for All expenses in Section 1-75(c)(1)(F) of the Act. While the Agency has generally adopted this approach of “backing out” a *program year’s* ILSFA expenses before determining the remaining available budget, it is unclear how that approach meshes with an upcoming *delivery year’s* expenses; as outlined above, because of the unpredictable nature of project energization timelines, Illinois Solar for All expenditures in the 2021-22 delivery year could be greater than this annual program year allocation. Additionally, as these allocations are prospective expenses, they could likewise be understood as junior to any existing REC delivery contract expenses given the rank-ordering between (i) versus (i-5) in Section 1-75(c)(1)(F).

Pragmatic considerations

The primary pragmatic consideration worth highlighting is the administrative burden, confusion, and general messiness associated with “clawing back” any already-made payments under REC delivery contracts. Perhaps one could construct an argument that, for the sake of fairness, all Adjustable Block Program contracts should face similar payment obligation reductions regardless of payments already made to date. Because Small DG contract obligations are fully paid upon energization, placing all such ABP systems on equal footing would require recovering some portion of the one-time payments already made for systems energized by May 31, 2021. In theory, this approach could allow for an even pro rata deferral of payments by contract type, regardless of energization timing considerations. No party providing positions in the reopening of Docket No. 19-0995 expressly raised or requested that clawbacks be implemented in the event that payment obligations are unable to be met.²⁶⁵

The Agency believes any focus on already-made payments is an unadvisable approach for a multitude of reasons. A clawback of prior delivery years’ payments carries uncertainty of recovery, significant administrative burden and expense, and unknown potential consequences for customers (especially distributed generation project hosts—Illinois residents and businesses) who may be guaranteed a rebate on system purchase or financing equivalent only to that which is paid out under a REC delivery contract. One fear is that a clawback of already-made REC delivery contract payments could result in solar companies seeking partial recovery of corresponding payments already made to customers, creating massive confusion and negative customer experiences with a state-administered incentive program. To avoid this potential confusion, the Agency strongly believes a better approach is simply focusing on expenses associated only with the *upcoming* delivery year, the year for which funds on hand are insufficient to cover expenses, and implementing a payment deferral regime which brings those expenses in line with the available RPS budget.

Fairness considerations

The Agency believes that market participants developing new renewable energy projects in Illinois had no expectation that REC delivery contract payments could be subject to risk of reduction. Indeed, as described in Chapter 2, revisions to the RPS contained in Public Act 99-0906 were intended to give

²⁶⁵ See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 10.

market participants budget certainty necessary for successfully developing new projects in Illinois; unfortunately, corresponding revisions to Section 16-108(k) of the Public Utilities Act – which fail to effectively “wall off” funding from potential reconciliation once that funding has been committed under a REC delivery contract – have not proven sufficient for handling unexpected project energization delays caused by a global health pandemic.

Consequently, the Agency’s preferred approach to any payment deferrals is one which accomplishes the following:

- a) ensuring that REC delivery contract holders are, in all cases, ultimately made whole for performance (i.e., any impact to payments should operate only as temporary deferral of payment obligations, rather than reductions in contract value amount); and
- b) reducing the time period during which payment delays are felt by REC delivery contract holders to the maximum extent possible.

As discussed below, achieving those ends – as well as ensuring that REC delivery contracts define a Buyer’s performance obligations as operating consistent with a Commission-approved payment deferral regime – requires adoption of a uniform amendment to existing REC delivery contracts.

3.23.7. 2021-22 Delivery Year Payment Deferral Approach

With these and other considerations in mind, the Agency proposed, and the Commission approved, the following approach.

First, REC delivery contracts will continue to be paid in full for at least the first six months of the 2021-22 delivery year. This approach will hopefully create as little disruption as possible to all parties; Sellers will be ensured full, expected payments through the end of calendar year 2021, and Buyers will have perfect clarity as to their payment obligations until incorporating future adjustments. Because actual 2021-22 delivery year expenses will not be clear until observing energization patterns within that delivery year, this approach will allow for a deferral of payment obligations to occur with the best possible information about those obligations. As available funds for the 2021-22 delivery year are expected to be approximately 98% of projected expenses for Ameren Illinois, 82% for ComEd and 80% for MidAmerican (according to March 2021 IPA projections), funding should be sufficient to cover all expected costs over this initial period.

Second, by December 30, 2021, the IPA will provide a compliance filing in Docket No. 19-0995 updating the status of the RPS budget and outlining the RPS budget available at the conclusion of the calendar year for use in the remainder of the 2021-22 delivery year, as well as updated projected expenses for that upcoming period. By this time, the first two quarterly invoicing periods of delivery year 2021-22 will have been completed for Adjustable Block Program contracts, and utility-scale project contracts will likewise have provided six months of monthly invoices. This compliance filing’s updated estimates of projected expenses and available budget would then be utilized for implementing REC delivery contract payment deferrals and provide percentage-based payment obligation reductions for those projects subject to a deferral of payment obligations.

Third, the resulting payment deferrals will exempt both LTPPAs and the utility DG procurement expenses. Whatever reading one gives to Section 1-75(c)(1)(F) of the IPA Act, it seems likely that this set of contract holders had the expectation of that prioritizing “existing contractual obligations” in language signed into law in December 2016 would ultimately exempt

these contracts (which were developed and executed before enactment of Public Act 99-0906, and prior to any additional contracts being executed) from any reductions in payments in the case that RPS budgets proved insufficient to cover expenses. Exempting these agreements also offers administrative ease, as the contract form and structure of these agreements was developed in an entirely different timeframe and under different applicable law than with the development of REC delivery contracts executed since Public Act 99-0906's enactment.

Fourth, the Agency believes that prioritization should be offered to Illinois Solar for All contract expenses, and payouts under those REC delivery contracts will not be reduced or deferred. Section 1-75(c)(1)(F) can indeed be interpreted as prioritizing Illinois Solar for All REC delivery contract expenses over Adjustable Block Program expenses or utility-scale REC delivery contract expenses; even if all such contracts could be considered "existing contractual obligations" as of March 2021, the drafters clearly believed that *some* priority should be assigned to Illinois Solar for All over other activities. Further, corresponding contracts with the IPA serving as the counterparty (paid out of the RERF) are not subject to these RPS budget constraints, and exempting utility-contracted Solar for All expenses from reduction thus keeps all Illinois Solar for All contracts on even footing (rather than disadvantaging particular Approved Vendors who happened to receive a utility counterparty agreement).

Fifth, the upcoming 2021-22 delivery allocations for Illinois Solar for All – including the \$10 million job training program allocation – will be maintained. REC delivery contract expenses for projects participating in the upcoming program year are unlikely to impact the 2021-22 delivery year budget, and the IPA understands Section 1-75(c)(1)(O)'s direction as essentially backing out job training program expenses before determining available budgets for other obligations.

Lastly, at the start of the 2022-23 delivery year, any payment deferrals implemented during the 2021-22 delivery year will immediately be prioritized as payments due to those Sellers in the first applicable invoicing cycle of the 2022-23 delivery year. Those expenses would thus be added to the 2022-23 delivery year expenses as the highest priority payments, and 2022-23 delivery year budget projections will be adjusted accordingly in line with these new costs. This approach will help ensure that any deferral of payouts serves only as a time-limited deferral of expenses, and as limited a deferral as possible at that.

To be clear, the above approach is not a solution to the current RPS budget situation. An actual solution can only be provided through legislation, and the Agency hopes that the process of working through these complexities heightens all parties' urgency in achieving a legislative fix. Instead, the above approach constitutes the Agency's best effort at emergency triage, and its attempt to limit the collateral damage resultant from an inherently problematic process brought on by an unprecedented global health crisis. In developing this approach, the Agency recognized that a payment reduction regime constitutes selecting between various flawed choices. The IPA believes the approach outlined above is sound, and the Commission agreed, confirming that the approach is prudent, reasonable, workable, well thought out, and most importantly, provides certainty and fairness to affected market participants.²⁶⁶

²⁶⁶ See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 27.

3.23.8. REC Delivery Contract Amendment

Ensuring that REC delivery contracts are ultimately paid in accordance with the approach outlined above and approved by the Commission will require modification to those contract forms which are potentially subject to payment deferral. Amending REC delivery contracts will help ensure that a Buyer is insulated from legal exposure for following a regulatory directive that may contradict a Seller's interpretation of its REC delivery contract, and will also ensure that the Seller has contractual rights around any deferred payments ultimately serving only as temporary deferral of those payment obligations.

For both programs and competitive procurements, exact contract language is not developed through a Commission proceeding; instead, the Agency's Procurement Administrator develops draft contract language consistent with Illinois law, the IPA's Plan, and the Commission's Order approving that Plan. Draft contracts are published for comment and feedback, and ultimately adopted only with the consensus of the IPA, ICC Staff, the Procurement Administrator, Procurement Monitor (where applicable), and the counterparty utilities (with the Commission resolving any disputes should those parties fail to achieve consensus).

Having received sufficiently specific direction from the Commission upon reopening in approving a contract payment deferral approach, the IPA will follow this contract development process for the development and adoption of any necessary REC delivery contract amendments. In accordance with its commitments made in Docket 19-0995 and the Commission's order, the Agency will target August 31, 2021 for finalization of the amendments reflecting the Commission's determinations on the issues outlined above. As implicit in the Commission's ruling approving the IPA's proposal, the Commission does not need to take further action before both Buyer and Seller would execute, and ultimately have their relationship governed by, that amendment.

3.24. Fall 2021 RPS Budget Update and Proposed Payment Deferral Regime for the 2022-2023 and 2023-2024 Delivery Years

3.24.1. Introduction

The Illinois Power Agency filed its petition to reopen ICC Docket No. 19-0995 on March 3, 2021. Commission approval of a payment deferral regime for the 2021-2022 delivery year came through an Order on Reopening on May 27, 2021. As of the time of publishing this draft Second Revised Plan, very little has materially changed since that time: the IPA published an updated RPS budget analysis in early June, reflecting quarterly invoice payments made in June for contract activity through May 31, 2021 (described in Section 3.24.2 below); the Agency and its Procurement Administrator drafted a draft REC delivery contract amendment, published that amendment for comment, and held a workshop on the amendment and received stakeholder feedback on that draft amendment.²⁶⁷ Legislation ultimately solving present RPS budget constraints has yet to advance in the Illinois General Assembly.

Most notably, neither the Agency, the utilities (Buyers under REC delivery contracts), renewable energy project developers (Sellers under REC delivery contracts), ICC Staff, or others have developed substantially more experience under the existing payment deferral regime than they had while offering arguments in the reopening of Docket No. 19-0995 across March, April, and May of 2021.

²⁶⁷ See: <https://www2.illinois.gov/sites/ipa/Pages/RenewableResourcesWorkshops.aspx> for more information on this process.

The comment process on draft payment deferral amendments to REC delivery contracts is still ongoing as of the date of this publishing, and thus open issues in implementing the payment regime outlined in Section 3.23 are still being worked through. In thinking through what approach should apply for future delivery years, these circumstances mitigate against any changes to the payment deferral approach approved by the Commission in its Order on Reopening in Docket No. 19-0995.

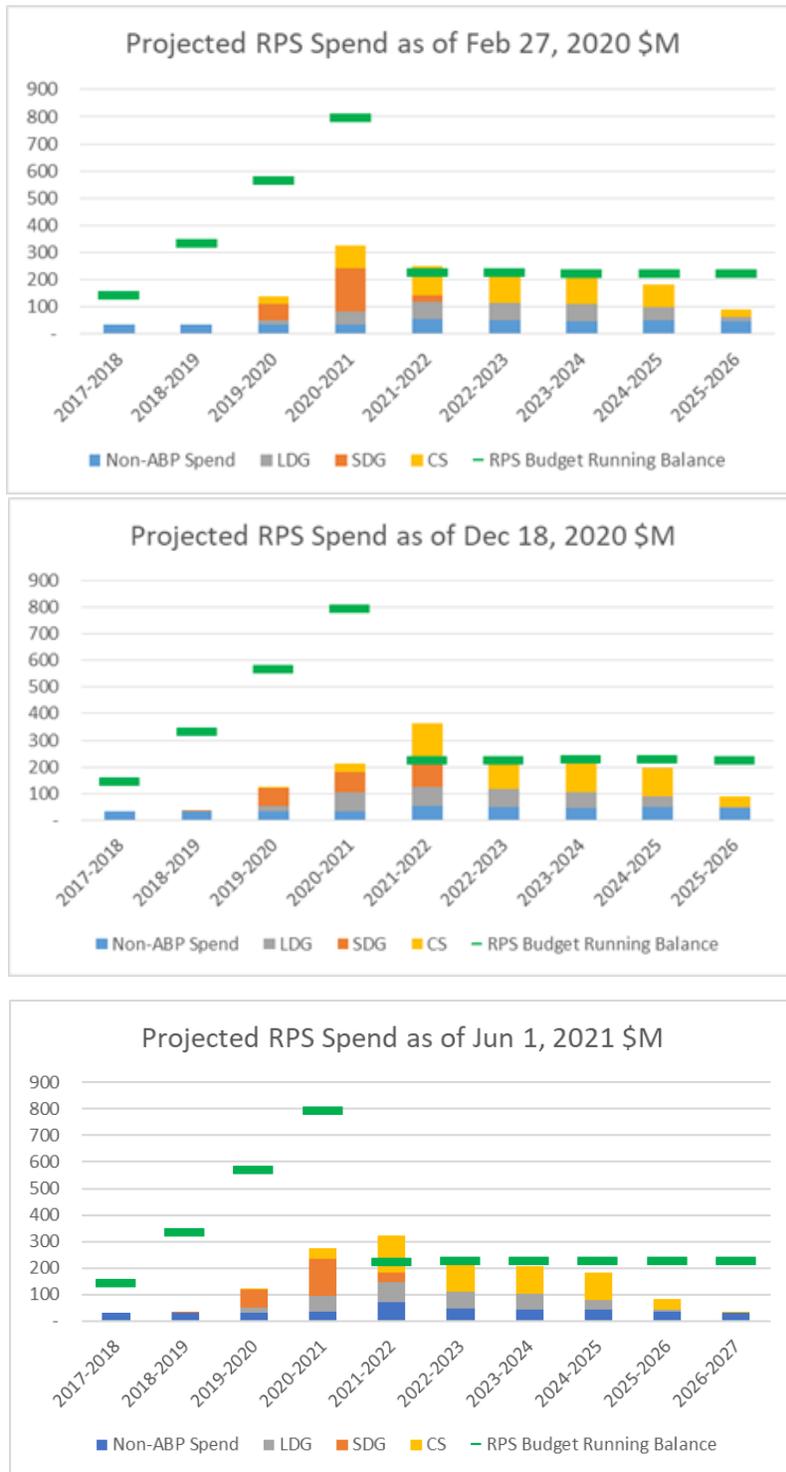
3.24.2. June 2021 RPS Budget Update

One new development since the Agency filed its Final First Revised Plan on Reopening in Docket No. 19-0995 was the IPA's June 2021 RPS Funding and Budget Update, the data and analysis underlying which is also incorporated, with certain data refreshed, into other tables within this Chapter 3. While this budget update did not alter the fundamental need to implement a payment deferral regime for the 2021-2022 delivery year, it did demonstrate an increased balance of expenses made in the 2020-2021 delivery year than had been modeled three or six months prior. Coupled with reduced anticipated expenses for the 2021-2022 delivery year, this left a reduced differential between expenses and funds available to meet those expenses for the 2021-2022 delivery year.

Table 3-3 from the June 2021 RPS Funding and Budget Update shows current expected spending. Figure 3-3 (based on the Agency's Revised Plan published in April 2020 reflecting pre-COVID energization assumptions from February 2020) and Figure 3-4 (the December 2020 update) are repeated here as part of Figure 3-5 below to demonstrate how this analysis has changed over time with periodically updated energization deadline extension and actual energization data.²⁶⁸

²⁶⁸ An updated Figure as of August 2021 is included earlier in this Chapter as Figure 3-2. The changes from June 2021 are de minimis.

Figure 3-5: Projected RPS Spending Changes Over Time



Reasons for the June 2021 Update's reduction in the differential between expenses and funds available for the 2021-2022 delivery year included the following. First, the June 2021 Update included actual project energization information through May 31, 2021 (which included projects invoicing in June 2021), rather than just projections. Second, the June 2021 Update incorporated updated information regarding the energization of utility-scale projects, including the removal of costs for projects not anticipated to be developed under REC delivery contracts and accounting for the lack of contracts awarded in the Spring 2021 utility-scale wind procurement event. Third, expected costs associated with RECs supplied by alternative retail electric suppliers (ARES) pursuant to the provisions of Section 1-75(c)(1)(H) of the Illinois Power Agency Act are now available were included in the budget projection for the 2021-2022 delivery year.

Due largely to the accelerated energization timetable of small distributed generation projects relative to prior projections (with REC delivery contracts for those projects, by law, paid entirely upon energization), the IPA's RPS budget projections now show a \$21 million statewide shortfall between expenditures and collections in the 2021-2022 delivery year even after the full balance of alternative compliance payments is taken into account. This is down from a \$67 million shortfall projection in December 2020 and a \$51 million shortfall projection in March 2021. The June 2021 Update demonstrated that delivery year collections plus utility-held alternative compliance payments *should* be sufficient to cover the full balance of Ameren Illinois RPS expenses for the 2021-2022 delivery year and in the delivery years thereafter, meaning that payment deferrals may not be required for REC delivery contracts featuring Ameren Illinois as a counterparty. Payment deferrals would still be required for ComEd and MidAmerican counterparty REC delivery contracts, both in the 2021-2022 delivery year and through the remaining periods covered under this plan revision (the 2022-2023 and 2023-2024 delivery years).

Increased expenses for the 2020-2021 delivery year through faster-than-expected small distributed generation project energization also resulted in a reduced amount projected to be refunded to customers after May 31, 2021. The June 2021 Update shows that, absent a change in state law, \$317 million is projected to be subject to reconciliation after the conclusion of the 2020-2021 delivery year. By utility, the IPA understands the anticipated refunded amounts to be broken down as follows:

- Ameren: \$111.9
- ComEd \$203.2
- MidAmerican: \$2.1

While \$317 million still a substantial amount of money collected to support renewable energy resource procurement but never able to be leveraged for that purpose, that \$317 million refund is down from the \$381 projected in December 2020.

The process and timing of any such refund is governed by, first, Illinois law which the Illinois Commerce Commission is tasked with interpreting (specifically Section 16-108(k) of the PUA), and second, electric utility tariff language developed in light of that language and previously approved by the ICC outlining the mechanics of the refund process. Based on the IPA's review of ComEd and Ameren's tariff language (Riders REA), the utilities will first perform a calculation to estimate the required adjustment between collections and expenses. Next, refunds of collections currently unspent (yet obligated to pay REC Contracts) are anticipated to begin under ComEd's Rider REA on its customers' September bills, and under Ameren's Rider REA on its customers' October bills. The IPA's review did not reveal evidence of the utilities' having discretion to hold back any of the

estimated over-collection, and the IPA understands that any such refunds would continue through to the customers' May 2022 utility bills.

This is the process which the IPA understands would follow from utility tariffs filed under existing state law. Should the Illinois General Assembly change the underlying law, however, the IPA understands that such refunds could potentially be halted. As of the time of publishing this draft Second Revised Plan, no such action has yet been taken by the General Assembly, although the topic of the anticipated refund has received some press attention.

3.24.3. Payment Deferral for 2022-2023 and 2023-2024 Delivery Years

Against the backdrop of a contract amendment process still underway and RPS budgets still projecting the need for payment deferrals, and given the recency of the First Revised Plan reopening proceeding, the Agency sees no reason to deviate from the process outlined in Section 3.23 for implementing a payment deferral regime should available funds be exceeded by expected expenses for the 2022-2023 or 2023-2024 delivery years. However, in publishing this draft Second Revised Plan, the Agency is interested in feedback from stakeholders about any open issues apparent from the contract amendment process or from the prior First Revised Plan Reopening proceeding.

The primary tenets of this payment deferral approach are as follows:

First, REC delivery contracts will continue to be paid in full for at least the first six months of the 2022-23 and 2023-24 delivery years. This approach will hopefully create as little disruption as possible to all parties; Sellers will be ensured full, expected payments through the end of a calendar year, and Buyers will have perfect clarity as to their payment obligations until incorporating future adjustments. **For the sake of clarity, pro rata contract payment deferrals would not take effect at the conclusion of six months; presently, the IPA believes that the best approach may be deferring any reductions in expected payments to as late in a given delivery year as possible, but is interested in stakeholder feedback on the appropriate approach.**

Second, by December 30th of 2022 and 2023, the IPA will provide a compliance filing in the proceeding approving this Second Revised Plan updating the status of the RPS budget and outlining the RPS budget available at the conclusion of the calendar year for use in the remainder of that delivery year, as well as updated projected expenses for that upcoming period. This compliance filing's updated estimates of projected expenses and available budget would then be utilized for implementing REC delivery contract payment deferrals and provide percentage-based payment obligation reductions for those projects subject to a deferral of payment obligations. The IPA will still publish biannual RPS budget projections independent of this filing, and may update its compliance filing in the case of updated RPS budget-related information.

Third, the resulting payment deferrals will exempt both LTPPAs and the utility DG procurement expenses (should any remain for the affected delivery years), as well as both actual and expected Illinois Solar for All expenses (including job training program allocations). This approach is consistent with the prioritization authorized by the Commission in its Order on Reopening in Docket No. 19-0995, through which it interpreted and applied provisions including Sections 1-75(c)(1)(F) and (O) of the Illinois Power Agency Act. The IPA sees no basis for deviating from the Commission's determinations in that proceeding, especially determinations which so recently interpreted and applied governing statute.

Lastly, at the start of the 2023-24 delivery year, any payment deferrals implemented during the 2022-23 delivery year will immediately be prioritized as payments due to those Sellers in the first applicable invoicing cycle of the 2023-24 delivery year. Similarly, at the start of the 2024-25 delivery year, any payment deferrals implemented during the 2023-24 delivery year will likewise be prioritized. This approach will help ensure that any reduction in payouts serves only as a time-limited deferral in expected revenues for Sellers under REC delivery contracts, and as time-limited a deferral as possible at that.

Again, the Agency hopes that feedback on its draft REC delivery contract amendment, coupled with parties' continued understanding of the concerns surrounding a payment deferral regime, will yield good feedback on the propriety of continuing this payment deferral approach in the delivery years ahead. And above all, the Agency hopes that some resolution on pending legislation can be reached such that this ongoing emergency patchwork process is no longer necessary. Until such time, however, the IPA believes the above payment deferral approach best tracks with the governing law while offering as little disruption and uncertainty to affected parties as possible.

4. Renewable Energy Credit Eligibility

To be eligible for use in compliance with the Illinois RPS, RECs are required to meet a variety of eligibility requirements. First, the RECs are to be sourced from generating technologies permitted in the definition of “renewable energy resources” contained in Section 1-10 of the Act.²⁶⁹ Second, Subsections (I) and (J) of Section 1-75(c)(1) create additional eligibility criteria. Subsection (I) contains locational eligibility criteria, while subsection (J) contains criteria related to how a facility that generates RECs recovers its costs. This Chapter discusses how the Agency interprets and implements the requirements of Subsections (I) and (J).

4.1. Adjacent State Requirement

Section 1-75(c)(1)(I) of the Act contains a locational eligibility requirement for the Illinois RPS. Enacted through P.A. 99-0906, this requirement replaced the prior locational standard under which renewable energy resources could come from Illinois and adjoining states, and if not available, then they could come from elsewhere.²⁷⁰ By contrast, Section 1-75(c)(1)(I) permits that qualifying renewable energy credits can be generated by facilities located in Illinois, and *may* be sourced from facilities in adjacent²⁷¹ states—but *only* if these facilities can meet public interest criteria spelled out in the law. While not explicitly stated in the statute, the Agency understands that the application of the public interest criteria for only adjacent states means that renewable energy credits from generating facilities located in states that are not adjacent to Illinois (or from generating facilities in other countries) will not be eligible for the Illinois RPS.

The public interest criteria that the Agency considers include:

1. Minimizing sulfur dioxide, nitrogen oxides, particulate matter and other pollution that adversely affects public health in this State
2. Increasing fuel and resource diversity in this State
3. Enhancing the reliability and resiliency of the electricity distribution system in this State
4. Meeting goals to limit carbon dioxide emissions under federal or state law
5. Contributing to a cleaner and healthier environment for the citizens of this State

The Act specifies that the Agency “may qualify renewable energy credits from facilities located in states adjacent to Illinois if the generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents based on the public interest criteria described above.”²⁷²

²⁶⁹ That definition is: “[r]enewable energy resources’ includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. ‘Renewable energy resources’ does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.” (20 ILCS 3855/1-10). Note that Public Act 99-0906 removed “other alternative sources of environmentally preferable energy” from this definition.

²⁷⁰ Former 20 ILCS 3855/1-75(c)(3), repealed June 1, 2017.

²⁷¹ For the purpose of assessing eligibility for compliance with the Illinois RPS, the Agency defines only states that have a common border as states adjacent to Illinois: Wisconsin, Iowa, Missouri, Kentucky, Indiana, and Michigan. Michigan is considered adjacent due to the border between Illinois and Michigan that exists in Lake Michigan. This is consistent with how other State Agencies interpret the federal Coastal Zone Management Act. See, for example, https://www.dnr.illinois.gov/cmp/documents/3_boundary.pdf.

²⁷² 20 ILCS 3855/1-75(c)(1)(I) (emphasis added).

To do so, and to “ensure that the public interest criteria are applied to the procurement and given full effect,” the Plan “shall describe in detail how each public interest factor shall be considered and weighted for facilities located in states adjacent to Illinois.” This Chapter provides that description.

In originally developing a methodology for considering and weighting these public interest criteria, the Agency faced certain challenges. The complex nature of an interconnected electric power grid and associated system operations (i.e., generation dispatch for economics and reliability), and how pollution flows across states, all prevented the Agency from simply quantifying and scoring facility eligibility requests using easily obtainable data. While predictions can be simulated, there is not one clear, unassailable way to determine how a renewable energy facility in an adjacent state will meet the public interest criteria.

In its Initial Plan, the Agency developed what it believes are reasonable proxies for each criterion.²⁷³ In the Final Order approving the Initial Plan on April 3, 2018 in Docket No. 17-0838, the Commission found the Agency’s methodology and assumptions for considering the eligibility of RECs sourced from adjacent states to be reasonable. That approach remained the same for the First Revised Plan approved by the ICC on February 18, 2020 in Docket No. 19-0995, and no party contested the First Revised Plan’s approach through that proceeding. This approach, described in more detail below, is generally unchanged in this Second Revised Plan.

While based conceptually on the same approach used for the Agency’s Zero Emission Standard (“ZES”) Plan, the basis for determining compliance with the pollution and emissions public interest criteria in this Revised Plan is focused on the displacement of potential new non-renewable gas-fired generation by renewable generation that could be eligible to supply RECs to meet the Illinois RPS requirements. Among the differences from the ZES Plan scoring approach are that renewable generating facilities are likely to be intermittent rather than baseload (a defining characteristic of zero emission facilities), typically impact generation on the margin of the dispatch order, and are generally smaller in size relative to the ZES replacement generation.

To assess whether a renewable generating facility located in an adjacent state is eligible to participate in the IPA’s REC procurements to meet the Illinois RPS, the Agency assigns a maximum of 20 points to each of the five public interest criteria, as described below, for a total of 100 possible points.

For a renewable energy generating facility in an adjacent state to have its RECs considered eligible for the Illinois RPS, the adjacent state facility needs to demonstrate that it can achieve a total score of at least 60 points for the Agency to approve that request. The IPA believes that this score threshold, previously affirmed by the ICC in Docket No. 17-0838, provides a balanced approach to ensuring that adjacent state facilities indeed provide sufficient benefits consistent with the law’s directive. This score threshold requires a better than average score demonstrating benefits to the health, safety, and welfare of Illinois residents, but yet not too onerous to prohibit any adjacent state participation.

For this draft Second Revised Plan, the Agency has reviewed and analyzed not only this scoring threshold, but also the methodology for the consideration of adjacent state facilities. After review and analysis, this scoring threshold and methodology (described further below) remains the same as

²⁷³ The Agency also developed a similar set of criteria for use in its Zero Emission Standard Procurement Plan (“ZES Plan”) developed pursuant to Section 1-75(d-5) of the Act, which was approved by the Commission on September 11, 2017 in Docket No. 17-0333. That ZES Plan includes consideration of how to minimize sulfur dioxide, nitrogen oxide, and particulate matter emissions that would result from the potential closure of zero emission facilities (i.e., nuclear plants located in PJM or MISO).

presented in the Initial Plan and First Revised Plan. However, the Agency has updated the data for the inputs related to wind direction and duration used in the methodology.

The Agency also notes that there are two wind facilities in adjacent states that were the recipients of contracts from the 2010 Long-Term Renewable Resources Procurement. One in Iowa has a contract with Ameren, while one in Indiana has a contract with ComEd. As these facilities were granted contracts at a time that Illinois law viewed them as providing sufficient benefits to Illinois residents for their renewable energy resources to be used to meet the Illinois RPS, the Agency considers these two facilities to be grandfathered into this requirement.

4.1.1. Public Interest Criteria

1. Minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State

In the Zero Emission Standard Procurement Plan, the Agency developed a scoring methodology for sulfur dioxide, nitrogen oxide, and particulate matter that considered the likely location of replacement generation compared to a bidding zero emission facility that could be at risk of ceasing operation. That methodology calculated, for any given zero emission facility, the percentage of the replacement generation that would occur in various states, an emissions factor related to each of those states based on its existing coal and gas generation, and an adjustment factor that recognized the frequency of prevailing winds and the distance from Illinois that could predict the amount of pollution that would impact the residents (and thus public health) of Illinois.

For the purposes of its Initial Plan (and maintained in this Second Revised Plan) and the consideration of this criterion, the Agency refined and simplified the methodological approach utilized in the ZES Plan. Under the ZES Plan, emissions are associated with replacement of generation that can be located anywhere in PJM or MISO; for the purposes of this Second Revised Plan, the Agency considers that a renewable energy facility would displace the emissions of a typical new natural gas-fired combined-cycle generation facility.

In the ZES Plan, the Agency weighted replacement generation across multiple states, in recognition that replacement generation for a large Zero Emission Facility would likely come from multiple sources (replacement generation would be a combination of changed dispatch of existing generation units as well as the potential development of new generating units).²⁷⁴ The Agency simplified the weighting for this criterion to focus on comparing emissions from renewable generation to the emissions from a new natural gas-fired combined-cycle generating facility. This assumption reflects the fact that recent and anticipated additions to the resource mix in PJM and MISO will be predominantly natural gas, wind or solar²⁷⁵ and natural gas is increasingly the fuel on the margin for both PJM and MISO, and thus more appropriate for comparison than, say, a baseload coal facility.²⁷⁶

²⁷⁴ Specifically, 33% of the replacement generation was assumed to be in the bidding zero emission facility's own state, and the remaining 67% of replacement generation was assumed to occur across the relevant RTO, allocated by states based on each state's share of RTO-wide generation. ZES Plan, July 31, 2017, <https://www.icc.illinois.gov/downloads/public/edocket/451223.pdf>, at 37.

²⁷⁵ U.S. FERC, Office of Energy Policy and Innovation, Division of Energy Market Assessment, "State of the Markets 2020. A Staff Report to the Commission," March 18, 2021. "MISO Futures Report," April 2021. <https://cdn.misoenergy.org/MISO%20Futures%538224.pdf>. Lustig, M. and Dholakia, G., S&P Global Market Intelligence, "Outlook 2021: US planned capacity additions again led by solar, wind." 26 April 2021.

²⁷⁶ See: Potomac Economics, "2020 State of the Market Report for the MISO Electricity Markets, Analytic Appendix" May 2021. <https://cdn.misoenergy.org/2020%20State%20the%20Market%20Analytical%20Appendix552300.pdf>; Monitoring Analytics, LLC, "2020 State of the Market Report for PJM, Volume 2: Detailed Analysis." http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol2.pdf.

As discussed below, this comparison is a relevant factor in the evaluation criteria for renewable technologies that involve combustion (thus not including wind, solar, or hydro).

The emissions comparison includes sulfur dioxide (SO₂) and nitrogen oxides (NO_x) as proxies for all emissions because higher emissions of SO₂ and NO_x are generally correlated with higher emissions of PM, especially with regard to facilities that involve the combustion of solid fuels. SO₂ and NO_x are primary emission sources for the formation of PM_{2.5} in ambient air away from the immediate emissions source. Larger PM (PM₁₀) is deposited nearer the source, while secondary PM_{2.5} increases based on the formation of sulfates and nitrates from the SO₂ and NO_x in the atmosphere as the pollutants move away from the primary source.²⁷⁷ The following table shows SO₂, NO_x, and CO₂ emissions rates of new natural gas-fired generation based upon 2019 data from the U.S. Energy Information Agency (“EIA”).²⁷⁸

Table 4-1: Natural Gas-Fired Combined-Cycle Generation Emissions Rates

Pollutant	Pounds/MWh
SO ₂	0.006
NO _x	0.048
CO ₂	752

The score is calculated by multiplying an emissions factor for the renewable resource facility (scaled from 0 to 1) by a wind duration/direction factor (scaled from 0 to 1) and then by 20 points to determine the number of points awarded for this criterion.

The emissions factor is calculated by taking one minus: the sum of the eligible renewable resource’s SO₂ and NO_x emissions in pounds/MWh divided by the sum of the SO₂ and NO_x emissions from a new natural gas-fired combined-cycle generation facility in pounds/MWh.

The emissions factor for renewable energy generating facilities such as wind, solar, or hydro, which do not emit SO₂, NO_x, or Particulate Matter, would be 1.0 because those facilities would have zero in the numerator of the part of the equation that is subtracted from one.

For other renewable generating technologies, the Agency notes that those technologies eligible for the Illinois RPS include a combination of technologies that rely on combustion of a fuel source including biodiesel, anaerobic digestion (which presumably would create a biogas that is then burned), biomass, and tree waste; and other technologies that do not involve combustion (e.g., wind, solar thermal, photovoltaic, and hydro power).²⁷⁹ Renewable generation technologies that involve combustion to generate electricity generate sulfur dioxide, nitrogen oxides, particulate matter, and CO₂, among other things. To assess the emissions impact of renewable resource technologies that involve combustion, the emissions from these facilities are compared to the emissions from a new natural gas-fired combined-cycle facility. To the extent that the technologies that involve combustion generate SO₂ and NO_x emissions, and the emissions in pounds/MWh are lower than the emissions

²⁷⁷ U.S. EPA, “Particulate Matter Emissions,” Report on the Environment, <http://www.epa.gov/roe>.

²⁷⁸ Emissions rates for a natural gas turbine operating in combined cycle with a heat rate of 6,431 Btu/kWh are shown in Table 7-3 of the February 2020 U.S. EIA Report “Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies.” The CO₂ emissions in pounds per MMBtu are 117 for CO₂, 0.001 for SO₂, and for NO_x 0.0075; which at the heat rate of 6,431 Btu/kWh, are 752 pounds per MWh of CO₂, 0.006 pounds per MWh of SO₂, and 0.048 pounds per MWh of NO_x. See: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf. Typical emissions rates have not changed since 2016, although the updated report shows that the new combined cycle generating plant heat rate has improved slightly.

²⁷⁹ While landfill gas produced in Illinois is eligible, it is not relevant to this discussion of facilities located in adjacent states.

from a new gas-fired facility, then the calculation for the renewable energy facility would result in the facility receiving some points for this criterion based upon the formula listed below that also accounts for wind duration/direction (as would be the case for technologies with no emissions such as wind or solar for which the points would only be based on the wind duration/direction and not discounted by emissions rate). On the other hand, if the emissions are equal to or greater, on a pounds/MWh basis, than from a new natural gas-fired facility, then the calculation would result in the facility receiving zero points for this criterion. This reflects that an emissions rate that is greater than that for a natural gas-fired combined-cycle facility does not have a positive impact on the environment and public health.

The Zero Emission Standard Plan included consideration of wind direction and duration as well as the distance from Illinois to modify the emissions criteria scoring. In scoring the emissions related public interest criterion, the Agency and simplified the wind duration/direction approach compared to what was utilized in the Zero Emission Standard Plan. For this Second Revised Plan, the IPA has updated the wind data from what was used in the Initial and First Revised Plans. Since the renewable generating facilities supplying RECs from outside of Illinois must be located in the states adjacent to Illinois (as opposed to anywhere within PJM and MISO under the Zero Emission Standard), the distance of the emission source from Illinois is less important for this Plan compared to the Zero Emission Standard, and thus is not considered in the approach adopted for this Second Revised Plan.

The following table provides the wind duration/direction factors for each adjacent state.

Table 4-2: Wind Duration/Direction Factors

Adjacent State	Wind Direction Sectors	Wind Direction and Duration Factor ²⁸⁰
Indiana	SSE, SE, ESE, E, NNE, NE, ENE	0.318
Kentucky	S, SSE, SE	0.213
Missouri	W, WSW, SW, SSW, S	0.460
Iowa	W, WNW, NW, NNW	0.253
Wisconsin	N, NNW	0.088
Michigan	NE, NNE	0.084

The wind duration factor is based on the percentage of the time the wind blows into Illinois from 16 directional sectors that form all of the directions in 360 degrees around Illinois. The wind direction and duration factors were developed based on 25 years of consistent climatological data. On average this data is relatively stable over time, although at some point in the future climate change could impact the data underlying the determination of these factors. For example, the wind blowing from Indiana would encompass seven directional sectors from which the wind blows on average 25.6 percent of the time. Thus, for example, a solar facility located in Indiana would receive $1 \times 0.318 \times 20$ or 6.36 points. The following equation shows how this score is obtained (with the caveat that the minimum possible score is zero and cannot be a negative score):²⁸¹

²⁸⁰ Total factors exceed 1.0 because there may be more than one state represented in a given wind direction sector.

²⁸¹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 21.

Figure 4-1: Pollution Score Calculation

$$Score = \left(1 - \frac{\sum_{renewable\ resource} SO_2\ and\ NO_x \left(\frac{lbs}{MWh} \right)}{\sum_{gas\ resource} SO_2\ and\ NO_x \left(\frac{lbs}{MWh} \right)} \right) \times Wind\ Duration\ /\ Direction\ Factor \times 20$$

The Agency’s review of the scoring methodology for this criterion showed that the analytical approach remains valid for this draft Second Revised Plan. However, the wind duration/direction factors have been updated to include 25 years of consistent data reported by the Illinois State Water Survey, Water and Atmospheric Resource Monitoring Program from 17 reporting stations located around the state for the years 1996 through 2020²⁸² (rather than the period 1996 through 2016 included in the Initial and First Revised Plans).

2. Increasing fuel and resource diversity in this State

Fuel and resource diversity generally refers to the use of a balanced group of generating facilities and technologies which results in reducing the risk that a specific technology could adversely impact overall system reliability. For example, PJM defines fuel diversity as: utilizing multiple resource types to meet demand such that a sufficiently diversified system is expected to provide the flexibility and adaptability to: “1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks.”²⁸³ In effect, fuel and resource diversity can act as a hedge to help ensure a stable and reliable supply of electricity.

Any generation source that promotes more reliance on generation sources other than coal and nuclear, which in 2020 had generation shares of 17.9% and 57.8% of Illinois’ total generation respectively,²⁸⁴ would contribute to increasing fuel and resource diversity in Illinois. By this measure, any of the eligible renewable energy resource generating technologies would contribute to diversity in Illinois. However, if these facilities were located outside of Illinois, in the adjacent states, the full impact on the State’s fuel and resource diversity would depend on whether the electricity generated by these facilities could actually be available to Illinois end-users.

Given that renewable generation accounts for only a relatively small fraction of the resource mix in Illinois (10.2% of total generation in 2020),²⁸⁵ an increase of renewable generation in the region may, in theory, increase the fuel and resource diversity of Illinois. However, the Agency notes that Illinois is a net exporter of electricity, so the impact on fuel and resource diversity in Illinois may be limited for facilities located in adjacent states. While Illinois is a net exporter of electricity, that does not mean that there is no impact on Illinois from electricity generated in adjacent states, because on an hour-to-hour basis electricity may flow into, or out of, Illinois. To the extent that any electricity

²⁸² <http://dx.doi.org/10.13012/J8MW2F2Q>.

²⁸³ PJM, “PJM’s Evolving Resource Mix and System Reliability,” March 2017, available at: <http://www.pjm.com/~media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx>.

²⁸⁴ U.S. EIA, “Electric Power Monthly with data for December 2020, February 2021.” The Agency notes that the share of coal declined from 38% and share of nuclear increased from 50.2% as reported in the Initial Plan. This is a net decline in the percentage of generation that comes from coal and nuclear (88.2% to 76%), which indicates that the fuel and resource diversity of the state has increased.

²⁸⁵ Id.

generated outside of Illinois but consumed in the state is generated by resources other than coal or nuclear, this generation is assumed to add to the fuel and resource diversity in Illinois.

In addressing this issue for facilities located in the adjacent states, the Agency uses the location of the renewable resource facility relative to Illinois as the basis for modifying the fuel and resource diversity score. A distance factor is calculated for each facility.²⁸⁶ The distance factor is based on the distance from the facility to Morris, Illinois (which is the city closest to the population weighted geographic center of Illinois,²⁸⁷ and thus can serve as a reasonable proxy for the load-weighted center of the state). The factor is calculated as 1 minus the ratio of (i) the distance from the facility to Morris and (ii) 470 miles, which is roughly the furthest point in an adjacent state from Morris. Consistent with the Commission’s Order in Docket No. 17-0838, the center point of the City of Morris is used for this calculation.²⁸⁸ That factor is multiplied by the maximum possible 20 points to provide the score for this criterion for potentially eligible renewable resource facilities located in adjacent states. The fuel and resource diversity score formula is shown in Figure 4-2.

Additionally, consistent with the Commission’s Order in Docket No. 17-0838 and the approach taken with respect to the third criterion below, a facility “that is not connected to either PJM or MISO” will receive a Fuel and Resource Diversity Score of zero.²⁸⁹ Adjacent state generation facilities “within a transmission control area that have a transmission usage agreement with PJM or MISO” may still receive non-zero scores under Criteria 2 and 3, however.²⁹⁰

Figure 4-2: Fuel and Resource Diversity Score

$$\text{Score} = (1 \text{ if in PJM/MISO, else } 0) \times \left(1 - \frac{\text{Distance from facility to Morris, IL (miles)}}{470 \text{ miles}} \right) \times 20$$

3. Enhancing the reliability and resiliency of the electricity distribution system in this State.

While this criterion references the “electricity distribution system” and that term is generally understood to mean the local distribution system that serves homes and businesses and not the transmission grid that transports power over longer distances (and across state lines), the Agency was originally concerned that, read literally, there would be no direct way for a facility in an adjacent state to meet this criterion because a facility in an adjacent state would have (at best) only an incidental impact on the distribution system (or more accurately systems, each operated by a different utility) within Illinois. With that in mind, the Agency has come to interpret this criterion more expansively and instead considers the impact on the grid more generally, as distribution service is ultimately supported by the reliability of transmission service. The scoring for this public interest

²⁸⁶ Because wind farms cover a large geographic area, a wind farm’s distance would be based on the geographic center of the area containing turbines that are part of that wind farm.

²⁸⁷ Based on the 2010 Census. See: https://www2.census.gov/geo/docs/reference/cenpop2010/CenPop2010_Mean_ST.txt.

²⁸⁸ See Docket No. 17-0838, Final Order dated April 3, 2018 at 21.

²⁸⁹ Id. The Commission also offered that “if a facility is not connected to PJM or MISO, it should not be allowed to participate in Illinois’ RPS procurement;” the Agency believes that because such a facility would score 0 out of 20 points on Criteria 2 and 3 and given the 60 point threshold, an adjacent state facility not connected to PJM or MISO would effectively be eliminated from consideration and no further scoring adjustments must be taken to give effect to the Commission’s intent.

²⁹⁰ Id.

criterion involves a threshold and, based on the assumption that generating facilities located closer to Illinois would have a more beneficial impact on the State’s distribution system reliability and resiliency, a distance factor. The criterion can be understood to refer to the transmission systems operated by PJM and MISO. To the extent that a facility in an adjacent state is not interconnected to the PJM or MISO grid (for example, in the portions of Iowa and Missouri that are part of the Southwest Power Pool (“SPP”)), those facilities would not score any points for this criterion. Otherwise, a facility in an adjacent state that is in either of the PJM or MISO control areas (or “within a transmission control area that has a transmission usage agreement with PJM or MISO”) would be eligible to receive points. To obtain the distance factor, the Agency uses an approach that considers proximity to Illinois and thus an increased likelihood that electricity produced will provide increased system reliability and resilience.

The scoring for this public interest criterion involves the same distance factor as is applied to the fuel and resource diversity scoring; the formula for determining this factor is shown in Figure 4-3. The Agency’s review of the scoring methodology and assumptions for criteria 2 and 3 confirms that distance is the factor which can be effectively incorporated into a simplified approach to determine the relative contributions of RECs from adjacent state renewable resources to meeting these public interest criteria.

Figure 4-3: Reliability and Resiliency Score

$$Score = (1 \text{ if in PJM/MISO; else } 0) \times \left(1 - \frac{\text{Distance from facility to Morris, IL (miles)}}{470 \text{ miles}} \right) \times 20$$

4. Meeting goals to limit carbon dioxide emissions under federal or State law

At the federal level, on June 19 2019, the U.S. EPA issued the Affordable Clean Energy Rule (ACE) as the replacement for the Clean Power Plan. The ACE focused on heat rate improvement at individual coal-fired power plants as a means to reduce CO₂ emissions by improving plant operating efficiency. ACE did not contain specific CO₂ emissions limits; instead, ACE provided guidelines for states to follow in limiting CO₂ emissions.²⁹¹ In January of 2021 the DC Circuit Court vacated ACE.²⁹² As of the release of this draft Second Revised Plan, clean energy standards remain a topic of debate at the federal level.

At the state level, Illinois does not have a specific law that limits carbon dioxide emissions. However, there are multiple provisions of Illinois law, such as the Zero Emission Standard and the Renewable Energy Portfolio Standard, that recognize the value of minimizing carbon dioxide emissions even if those provisions do not create explicit limits. To recognize the value in reducing carbon dioxide emissions, the Agency determines the score for each renewable resource facility by adjusting the 20 points available for this criterion by a factor which reflects the ratio of the CO₂ emissions from the renewable resource to the CO₂ emissions from a new natural gas-fired combined cycle generating facility, 752 pounds of CO₂ per MWh, as shown in Table 4-1 above. This is done by using the formula

²⁹¹ <https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan>.

²⁹² See: <https://www.natlawreview.com/article/dc-circuit-vacates-trump-ace-rule-what-s-next-power-plant-co2-regulation>.

applied to the first emissions criterion except that the inputs are pounds of CO₂ emitted per MWh. The factor applied to the 20 points available for this public interest criterion is calculated as follows:

Figure 4-4: CO₂ Score Calculation

$$Score = \left(1 - \frac{CO_2 \text{ renewable resource} \left(\frac{\text{lbs}}{\text{MWh}} \right)}{CO_2 \text{ gas resource} \left(\frac{\text{lbs}}{\text{MWh}} \right)} \right) \times 20$$

Renewable generating facilities that do not emit any CO₂ receive the full 20 points, while renewable generating facilities that emit CO₂ receive points based on the factor multiplied by the 20 points. Because CO₂ emissions are generally considered to be a global problem (in that CO₂ emissions anywhere on the planet contribute to global warming, which then affects the health and welfare of the citizens of Illinois), wind direction, duration, and distance from Illinois’s load-weighted center are not relevant for the scoring of this criterion and therefore are not included in the calculation.²⁹³ Comparing the CO₂ emissions from each renewable resource to the emissions from the most likely alternative generation, usually a gas-fired combined-cycle plant, remains a practical means for determining the score for this criterion.

5. Contributing to a cleaner and healthier environment for the citizens of this State

This criterion is arguably the most subjective in nature, and presents unique challenges given that the Agency strives to use objective approaches to the greatest extent possible when considering the public interest criteria. The Agency believes that renewable resources inherently contribute to a cleaner and healthier environment generally (with the caveat related to emissions from renewable resources that involve combustion, discussed above) because they reduce the reliance on fossil fuels and have no safety issues associated with the containment and disposal of radioactive materials that result from nuclear generation. Under this Second Revised Plan, the points awarded for this public interest criterion are the average of the points awarded under the first and fourth public interest criteria described above. This approach takes into account the emissions from renewable resource facilities that involve combustion and, subsequently, emissions, which would not contribute to a cleaner and healthier environment for the citizens of Illinois.

4.1.2. Application Process

The eligibility of RECs from renewable energy generating facilities located in states adjacent to Illinois is not automatically granted, because the Act requires that approval comes only after “the generator demonstrates and the Agency determines” that the facility’s operation meets the public interest criteria discussed above.²⁹⁴ That determination requires an active request (demonstration)

²⁹³ The Agency notes that the Zero Emission Standard Plan contains a different scoring methodology for CO₂ emissions, but that methodology is based upon the impacts of replacement generation and the consideration related to “minimizing carbon dioxide emissions that result from electricity consumed in Illinois” (20 ILCS 3855/1-75(d-5)(1)(C)), which is not the same standard as under consideration in qualifying adjacent-state facilities for the RPS.

²⁹⁴ 20 ILCS 3855/1-75(c)(1)(I).

by an interested generator. Renewable generating facilities in adjacent states may apply to the Agency for consideration for eligibility for the RPS.²⁹⁵

Shortly after the approval of its Initial Plan, the Agency developed an application form (in the form of an Excel spreadsheet) for use by owners/agents of adjacent-state facilities that wish to have RECs from those projects considered to be eligible for the Illinois RPS.²⁹⁶ The information to be entered into the application form includes the generating technology (including information on emissions rates if the technology involves combustion), state where the generator is located, distance from the geographical center of Morris, IL, the Regional Transmission Organization (“RTO”) where the facility is or planned to be interconnected (e.g., PJM, MISO, SPP), and the tracking system ID (for existing facilities). The application form automatically calculates the score for the facility. In addition, the generator must also include information related to the provision limiting the recovery of costs in rates described in Section 4.2.

As discussed above, the Agency will continue to review and, as necessary, update the data used in the eligibility calculations on a bi-annual basis in conjunction with the Plan update to use the most recent available inputs (and has done so for this draft Second Revised Plan, determining that minor changes are needed for the wind direction/duration factors), but a facility’s determination of eligibility will be based on the data available at the time of the request for determination (in other words, a facility would not risk having its eligibility revoked at a later date if the inputs changed after the initial eligibility determination is made by the Agency).

The Agency will review applications to verify the information submitted (e.g., confirming the distance inputs), and if the facility has a score equal to or greater than 60 points (and meets the cost recovery requirement found in Section 1-75(c)(1)(J) of the Act, discussed further below), the Agency will approve the facility as eligible to produce renewable energy credits for compliance with the Illinois RPS. The Agency will inform the applicable tracking system (GATS or M-RETS) that the facility should be coded as Illinois RPS eligible.

In the case of a new adjacent-state facility that is not yet operational (and thus also not registered in GATS or M-RETS), an owner may submit a request for determination of eligibility based upon the planned design of the facility. If the Agency determines that the planned facility does meet the public interest criteria, then it will grant a pre-approval of the eligibility. It is the responsibility of the facility owner to notify the IPA and the tracking system once the facility is operational to request being coded as eligible for the Illinois RPS in the applicable tracking system. The Agency will review final system information to verify consistency with the information submitted for the pre-approval.

4.2. Cost Recovery Requirement

Section 1-75(c)(1)(J) of the Act contains the following provision:

In order to promote the competitive development of renewable energy resources in furtherance of the State's interest in the health, safety, and welfare of its residents, renewable energy credits shall not be eligible to be counted toward the renewable

²⁹⁵ An exception is made for the out-of-state facilities that have LTTPA contracts with the utilities. As discussed in Section 4.1, those facilities are grandfathered in and remain eligible to provide RECs for compliance with the Illinois RPS.

²⁹⁶ Available at: <https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/IL-RPS-Adjacent-State-Facility-Determination-of-Eligibility-20180404.xls>.

energy requirements of this subsection (c) if they are sourced from a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017.

Generally speaking, the Agency understands that facilities owned by a rural electric cooperative or a municipal utility are not impacted by this criterion (as in Illinois, those entities' rates are not regulated by this *state* or any other), although the Agency notes that there are certain adjacent states which regulate some rural electric cooperative and municipal utility rates. Therefore, the Agency cannot issue a blanket approval under this provision of facilities owned by rural electric cooperatives or municipal utilities service territories in adjacent states; rather, as those facilities request eligibility, their rate recovery status will be reviewed.

The Agency also understands that this provision was primarily intended to ensure that facilities owned by a vertically integrated utility, for which REC revenues may be incidental to building and financing the facility (as that facility's costs could be recovered from ratepayers in that other state, potentially resulting in a credit or discount to those ratepayers for any REC revenues—effectively causing Illinois ratepayers to cross-subsidize those in vertically integrated states) would not be eligible. Another situation that has been brought to the Agency's attention concerns a proposed project to be developed by an Illinois non-electric utility (a gas or water utility, for instance) featuring delivery service rates that are regulated by the Illinois Commerce Commission with cost recovery then sought over the cost of the renewable energy generating facility. Regardless of whatever may have been the primary purpose informing Section 1-75(c)(1)(J)'s enactment, this situation would seem to clearly fit Section 1-75(c)(1)(J)'s prohibition: the renewable generation facility's costs would be recovered through state-regulated rates. Consequently, the IPA understands such projects' RECs as being barred from participation in the Illinois RPS (including in, say, the Adjustable Block Program) insofar as rate recovery is sought for those projects.

On the other hand, the mere presence of a Power Purchase Agreement between a facility and a separate utility whose costs are recovered in regulated rates would not trigger these criteria (nor would participation in the IPA's energy procurement events, for which regulated utilities serve as contractual counterparties, or participation in a net metering or similar energy crediting program, which would serve to disqualify the very facilities that other portions of the Illinois RPS work to support). Likewise, the Agency believes that being a Qualifying Facility under the Public Utility Regulatory Policies Act ("PURPA")²⁹⁷ (and also meeting the other aspects of the requirements of the Illinois RPS), would not be disqualifying because the Qualifying Facility does not directly recover its costs through rates; rather, it is compensated for its energy at the purchasing utility's avoided cost rate.

As described in Section 4.1.2, facilities located in adjacent states must proactively request eligibility for the utility RPS pursuant to the public interest criteria standard explained above. Those requests to meet the public interest criteria are required to include a notarized certification, and documentation, that the facility does not have its costs recovered through regulated rates. For a distributed generation facility, simple documentation of ownership will suffice. For larger facilities, the Agency has not utilized a firm standard of documentation, but believes there are multiple approaches that could be used by a requesting facility. These include, but are not limited to:

²⁹⁷ 16 U.S.C. §§ 796(17), 824a-3, 824i.

- For facilities tracked in M-RETS, documentation to support the status listed in the “Facility Ownership Type” field
- A Market Based Rate authorization letter from the Federal Energy Regulatory Commission that demonstrates that the facility owner is not a utility with costs recovered through regulated rates
- Certification as a Qualifying Facility
- Use of information from other sources such as the S&P Global Intelligence Briefing Book, or the Platts UDI Directory of Electric Power Producers and Distributors

The Agency will review (in consultation with the ICC) information provided for a facility, and may, as needed, request additional information to verify a facility’s status.

In addition to the screening process described above, all contracts from IPA-administered REC procurements or programs utilized since the effective date of P.A. 99-0906 contain provisions to reflect this additional requirement of Section 1-75(c)(1)(J) (and will continue to do so going forward):

Each contract executed to purchase renewable energy credits under this subsection (c) shall provide for the contract's termination if the costs of the generating unit supplying the renewable energy credits subsequently begin to be recovered through rates regulated by this State or any other state or states; and each contract shall further provide that, in that event, the supplier of the credits must return 110% of all payments received under the contract. Amounts returned under the requirements of this subparagraph (J) shall be retained by the utility and all of these amounts shall be used for the procurement of additional renewable energy credits from new wind or new photovoltaic resources as defined in this subsection (c). The long-term plan shall provide that these renewable energy credits shall be procured in the next procurement event.

The Agency notes that Section 1-75(c)(1)(J) also provides a limited exception to this provision for facilities that participate in the Illinois Solar for All Program outlined in Section 1-56 of the Act:

Notwithstanding the limitations of this subparagraph (J), renewable energy credits sourced from generating units that are constructed, purchased, owned, or leased by an electric utility as part of an approved project, program, or pilot under Section 1-56 of this Act shall be eligible to be counted toward the renewable energy requirements of this subsection (c), regardless of how the costs of these units are recovered.

5. Competitive Procurement Schedule

As outlined extensively in Chapter 3, the current RPS budget situation demonstrates available funds as insufficient to meet contracted expected across upcoming delivery years. But with significant amounts of the RPS budget tied up through REC delivery contracts featuring 4 year payment obligations (community solar and Large DG projects) after that project's energization (see Figure 3-2), the IPA's RPS budget modeling demonstrates that funding will be available to support additional new renewable energy project REC deliveries beginning after those obligations end.

Further, unlike with Adjustable Block Program project development timelines (under which projects are expected to energize within 12 or 18 months of project application), new utility-scale wind, utility-scale solar, and brownfield site photovoltaic projects may take three years or more from REC contract execution through to energization and REC delivery commencement. As the IPA's next long-term planning process is currently set to conclude in early 2024, this Second Revised Plan—developed by the IPA in 2021, and approved by the ICC in early 2022—is the appropriate planning cycle for proposing competitive procurement events under which applicant new wind and solar projects would begin delivering RECs in the 2025-2026 delivery year.

Thus, as described throughout this Chapter, to help meet RPS goals outlined in Section 1-75(c) of the IPA Act, in this draft Second Revised Plan the IPA proposes to potentially conduct competitive procurements for RECs conducted during calendar years 2022 and 2023. In combination with the programs described in Chapters 6, 7, and 8, as limited by the RPS budget caps, these competitive procurements would help make progress toward the RPS REC goals and targets outlined in Sections 1-75(c)(1)(B) and (C) as further discussed in Chapter 3. However, as outlined in Chapter 3, the Agency envisions significant funding constraints over the next several years. As a consequence, this Chapter proposes to conduct 1) a utility-scale wind forward procurement intended to replace projects from prior procurements that will not be completed, and 2) a brownfield site photovoltaic procurement to meet 2025 REC targets. For any other competitive procurements, this Chapter merely provides a framework for possible additional procurements should those procurements become feasible due to a fundamental change in the Agency's analysis of available funds (including the allocation of utility-held ACPs) that could somehow both make all existing contract holders whole while staying within the IPA's budget margins, which would most likely only occur through legislative changes to RPS funding sources that do not involve this long-term planning process being scrapped and rewritten in compliance with new governing laws.

In the Initial Plan, this Chapter discussed two types of competitive procurements: Forward Procurements and Spot Procurements. The discussion further noted that pursuant to the Commission's Final Order in Docket No. 17-0838, the Initial Plan no longer contained proposals for Spot Procurements in the 2017-2018 through 2019-2020 delivery years,²⁹⁸ while Forward Procurement volumes were significantly increased through that Order (in both cases, compared to the Agency's proposed Initial Plan filed for the Commission's approval in December 2017). As taken from the Initial Plan, the Agency uses the following definitions of these types of procurements:

- A **Forward Procurement** is a competitive procurement for RECs where the beginning delivery date is in a future delivery year and the delivery term is multiple years. Further, a Forward Procurement is for utility-scale unit-specific RECs. Forward Procurements include

²⁹⁸ See Docket No. 17-0838, Final Order dated April 3, 2018 at 40-44.

those specifically outlined in the Act (e.g., a Subsequent Forward Procurement) and additional Forward Procurements proposed by the IPA as part of this draft Second Revised Plan. Unless specified otherwise in this Chapter, Forward Procurements will, to the extent practicable, follow the model used for the Initial Forward Procurement including:

- 15-year REC-only contracts
 - Price per REC fixed over the term of the contract, no price escalation
 - Ability to bank RECs
 - Credit requirements and instruments
- **A Spot Procurement** is a competitive procurement for RECs for either the prior, current, or the prompt delivery year goals. The delivery term of a Spot Procurement is one delivery year. While the IPA does not believe the PUA or IPA Act requires that spot procurement proposals track exactly on the requirements of Section 16-111.5, the Agency proposes that should any spot procurements be authorized and subsequently conducted, to the extent practicable, they would follow the model the IPA has used for past similar REC procurements including:
 - Fixed price per REC
 - RECs must be from applicable delivery year
 - Credit requirements and instruments

In this draft Second Revised Plan, the Agency continues to only propose potential Forward Procurements. While Spot Procurements may allow for continued progress toward the renewable energy credit procurement goals found in Section 1-75(c)(1)(B) of the Act, near-term budget constraints do not allow for procuring RECs from qualifying built and existing renewable energy projects for retirement across the years covered by this Second Revised Plan. Further, as forward procurements can be conducted with REC delivery timelines well into the future for projects not yet developed as of present, and as Section 1-75(c)(1)(F) of the Act demonstrates a statutory preference for meeting the quantitative targets of Section 1-75(c)(1)(C) (which are met in part through Forward Procurements designed to incent the development of new projects) over the percentage-based goals of Section 1-75(c)(1)(B) (which would require procurement strategies like Spot Procurements to be met), only Forward Procurements represent a competitive procurement strategy appropriate for this planning cycle.

5.1. Statutory Requirements

Section 16-111.5(b)(5)(ii)(B)(aa) of the PUA requires that this Plan:

“Identify the procurement programs and competitive procurement events consistent with the applicable requirements of the Illinois Power Agency Act and shall be designed to achieve the goals set forth in subsection (c) of Section 1-75 of that Act.”

The “competitive procurement events” contemplated by the IPA are discussed in this Chapter, while the “procurement programs” are discussed in Chapters 6, 7 and 8. Also specifically addressed in this chapter is the following additional provision (bb) of that subsection of the Act regarding REC procurements subsequent to the Initial Forward Procurement:

“Include a schedule for procurements for renewable energy credits from utility-scale wind projects, utility-scale solar projects, and brownfield site photovoltaic projects

consistent with subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act.”

Section 16-111.5(b)(5)(iii) further states that,

“For those renewable energy credits subject to procurement through a competitive bid process under the plan or under the initial forward procurements for wind and solar resources described in subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act, the Agency shall follow the procurement process specified in the provisions relating to electricity procurement in subsections (e) through (i) of this Section.”

While it is unclear whether procurements such as those proposed in this Chapter are *required* to be conducted as “a competitive bid process,” the Agency has achieved generally positive results in past experience with its competitive bid process (including the Initial Forward Procurements and competitive procurements conducted pursuant to the Initial Plan). Thus, outside of the programs proposed in later Chapters—some of which statutorily require a different structure—the Agency sees no need to deviate from this approach. Section 5.3 discusses the Agency’s competitive procurement process specified in Section 16-111.5(e) through (i) in more detail, and specifically how this process will be applied to the competitive procurements proposed in this draft Second Revised Plan.²⁹⁹

5.2. Background on past REC Procurements conducted by the IPA

In the years 2009 through 2016, with the exceptions of 2013 and 2014,³⁰⁰ the IPA held procurements for renewable energy resources to meet the RPS requirements of the utilities’ eligible retail customers. These procurements were conducted through a competitive procurement process.

While changes to Section 1-75(c) of the IPA Act through P.A. 99-0906 significantly increased the volume of RECs to be procured by the Agency, the Agency had a long track record of procuring renewable energy resources prior to P.A. 99-0906, predominantly RECs.³⁰¹

Prior to Public Act 99-0906, the Agency’s past competitive procurements for renewable energy resources are listed below (with the delivery quantities of RECs procured listed in some cases):³⁰²

²⁹⁹ The provisions related to this Plan contained in Section 16-111.5 of the PUA and Section 1-75(c)(1) of the Act generally refer to “competitive procurement processes” or “competitive procurement events” while in this one instance there is reference to “a competitive bid process” that shall follow the procurement process contained in Section 16-111.5. However, that provision only applies to the Initial Forward Procurement. Nonetheless, while the Agency may have the discretion to conduct other competitive procurement processes through procedures other than those envisioned by Section 16-111.5 (e.g., rather than a sealed bidding with pay-as-bid settlement, offering a standard offer price, or perhaps a single clearing price), at this time the Agency believes that all the competitive procurements it administers should follow the framework set up by Section 16-111.5.

³⁰⁰ In the Agency’s 2013 Procurement Plan, due to a decline of eligible retail customers’ load served by the utilities, mainly attributable to municipal aggregation, the Agency determined, and the Commission agreed, that no new procurements of renewable energy resources (or for that matter energy) were required. See Order, Docket No. 12-0544, December 19, 2012, at 109-110.

³⁰¹ Section 1-75(c) of the Act prior to the changes enacted through Public Act 99-0906 focused on the procurement of “renewable energy resources.” The revisions to the Section contained in Public Act 99-0906 focus the Long-Term Renewable Resources Procurement Plan on specifically acquiring “renewable energy credits” from programs and competitive procurements.

³⁰² Announcements of these procurements that contain additional information can be found at: <https://www.illinois.gov/sites/ipa/Pages/Prior-Approved-Plans.aspx>. Certain REC volume information has been redacted to maintain required confidentiality in accordance with 220 ILCS 5/16-111.5(h). Please note that because initial delivery timelines vary, the “per year” numbers may not be 100% accurate for a specific calendar period.

- Spot Procurements for one-year delivery of RECs
 - 2009 REC procurements for Ameren Illinois and ComEd (720,000 RECs for Ameren Illinois, 1,564,360 RECs for ComEd)
 - 2010 REC procurements for Ameren Illinois and ComEd (860,860 RECs and 1,887,014 RECs for Ameren Illinois and ComEd, respectively)
 - 2011 REC procurements for Ameren Illinois and ComEd (952,145 and 2,117,054 RECs)
 - 2012 REC procurements for Ameren Illinois and ComEd (523,376 RECs and 1,335,673 RECs)
 - 2015 SREC procurements for Ameren Illinois and ComEd (30,212 SRECs and 49,770 SRECs)
 - 2016 SREC procurements for Ameren Illinois and ComEd (33,271 SRECs and 67,952 SRECs)
 - 2016 REC procurement for MidAmerican

- Procurements for multiple delivery years of RECs
 - 2010 Long-term procurements for Ameren Illinois and ComEd (20 year contracts, bundled RECs and energy, 600,000 RECs per year and 1,261,725 RECs per year, respectively)
 - 2012 “Rate Stability” procurement for Ameren Illinois and ComEd (contracts for four years and seven months) (2,053,837 RECs over the delivery term, and 2,737,110 RECs over the delivery term, respectively)
 - 2015 Supplemental Photovoltaic procurements using the RERF (5 year contracts, with provision to allow time for identification of under 25 kW systems) (21,436 SRECs per year)
 - 2015 Distributed Generation procurement for Ameren Illinois and ComEd (5 year contracts)
 - 2016 Supplemental Photovoltaic procurement using the RERF (5 year contracts, with provision to allow time for identification of under 25 kW systems) (18,354 SRECs per year)
 - 2016 Distributed Generation procurement for Ameren Illinois and ComEd and MidAmerican (5 year contracts)
 - 2017 Distributed Generation procurements (5 year contracts, also include provision to allow time for identification of under 25 kW systems) (19,025 SRECs per year procured in Spring 2017, 8,153 SRECs per year procured in Fall 2017)

With the enactment of Public Act 99-0906, the Agency began conducting procurements to meet RPS requirements applicable to *all* retail customer sales. The first such procurements were the Initial Forward Procurements, conducted prior to the finalization of the Initial Plan. After the Initial Plan’s approval, the Agency conducted a series of procurements conducted under the Commission’s authority granted through its Order in Docket No. 17-0838. Those procurements are listed below:

- 2017 and 2018 Initial Forward Procurements (15 year contracts for new utility-scale wind and new utility-scale solar, 965,000 Wind RECs and 1,000,000 Solar RECs per year procured)

- October 2018 First Subsequent Forward Procurement (15 year contracts for new utility-scale wind, 1,979,753 RECs procured)
- November 2018 Photovoltaic Forward Procurement (15 year contracts for new utility-scale solar, 2,000,000 RECs)
- July 2019 Brownfield Site Forward Procurement (15 year contracts, quantity not released due to only two projects selected)
- Second Subsequent Forward Procurement (15-year contracts for new utility-scale wind). Two procurement events, conducted October 2019 and March 2021, No bids were accepted in either procurement;
- Community Renewable Generation Procurement (15-year contracts for non-PV renewable technologies). No bids were accepted;
- Low-income Community Solar Pilot Project Procurement (15-year contracts; conducted pursuant to Section 1-56(b)(2)(D) of the Act)

5.3. The Agency's Competitive Procurement Approach

Based on previous REC procurement experience, the Agency has a solid foundation to build upon for conducting the potential additional competitive procurements proposed in this draft Second Revised Plan. However, the Agency has conducted two utility-scale wind procurements that did not yield selected bids. While the Agency understands that the most recent drafts of omnibus proposed energy legislation would shift competitive procurements from a fixed REC price model to an indexed REC price model (where REC payments would fluctuate over time based on changes in energy prices), and would introduce additional RPS budget flexibility to accommodate the resulting variance in year-over-year RPS budget impacts, such legislation has not yet been enacted.

For this draft Second Revised Plan, the Agency is interested in stakeholder feedback on two topics. First if there are changes other than a change to the REC price from fixed to indexed that would encourage stronger participation in Agency competitive procurements. Second, if those changes would not be sufficient to elicit stronger participation in future procurements, or in addition to those changes, could the Agency implement a procurement that would feature some form of indexed REC price without statutory changes?

The Agency has previously had concerns with a non-fixed REC price approach because of the potential budget impacts resultant from a non-fixed REC price. However, the Agency has heard from the utility-scale renewable energy development community that they desire an indexed REC price approach to de-risk project development and reduce the need to find off-takers for the energy by allowing the projects to sell into the wholesale market.³⁰³

Given the lack of successful bids in the last two utility-scale wind procurements, the Agency seeks procurement model that would better recognize and balance these concerns. Areas for feedback could include, but are not limited to, how to evaluate bids (e.g., should the bid be a fixed first year price or some other amount), what would be reasonable collars around prices to address the budgeting uncertainty discussed above, and should the framework for credit

³⁰³ The Agency anecdotally understands that possible corporate energy off-takers are often interested in bundled REC and energy contracts and are thus not as interested in only purchasing the energy output of new utility-scale wind and solar projects if they cannot also buy those RECs (which under the Illinois RPS procurement model discussed herein are sold to the utilities).

and collateral requirements be adjusted to reflect the shift in risk that such an approach would entail.

The procurement approach the Agency has used for prior REC procurements, including the Initial Forward Procurements and the forward procurements conducted under the Initial and First Revised Plans, stems from the approach laid out in Section 16-111.5 of the Public Utilities Act for “standard wholesale product” (i.e., block energy, capacity, etc.) procurements. It includes the following key provisions:

- Standard contracts and credit provisions
- Sealed bids with pay-as-bid settlement
- Use of confidential benchmarks to eliminate bids not consistent with the market
- Bid selection based on price
- No post-bid negotiations
- Procurement Administrator evaluates bids and provides confidential recommendation to the Commission for approval
- Procurement Administrator provide bidder interface including training
- Uniform/standardized bid forms
- Uniform/standardized/harmonized credit requirements
- Procurement Monitor involvement

These provisions define a procurement process that has multiple stages.

- The Procurement Administrator develops draft contracts in consultation with the utilities, the Agency, the Procurement Monitor,³⁰⁴ and ICC Staff.
- Draft contracts are released for public comment.
- The Procurement Administrator, the Agency, the utilities, ICC Staff and the Procurement Monitor review all comments received on the draft contract and revise the contract as needed.³⁰⁵
- Typically, the Procurement Administrator holds an informational webcast upon release of the final contracts and RFP rules.
- Submission of Proposals is in two parts:
 - Part 1 for pre-qualification – allows bidders to provide basic information, and agree to the terms of the contract and the RFP rules.
 - Part 2 for registration of bidders – allows bidders to update information, make additional certifications including regarding confidentiality of bidding information, and post bid assurance collateral.
- Bids – on the bid date, bidders submit bids using a standardized bid form.
- Evaluation of Bids – the Procurement Administrator evaluates bids based on price, procurement objectives and priorities; identifies the winning bids; prepares a

³⁰⁴ The Procurement Monitor is an independent consultant that works on behalf of the Commission to oversee all aspects of the procurement process. 220 ILCS 5/16-111.5(c)(2).

³⁰⁵ If agreement between the Procurement Administrator and the utilities is not reached on the terms and provisions of the contracts, any disputes are resolved by the Commission. (See 220 ILCS 5/16-111.5(e)(2)).

recommendation for the Commission. The Procurement Monitor observes the bidding and evaluation process and makes its own recommendation.³⁰⁶

- Commission decision – After review of the Procurement Administrator’s and Procurement Monitor’s reports and recommendations, the Commission renders a decision on the results of the procurement event.³⁰⁷
- Release of procurement results – The Procurement Administrator releases the results of the procurement event; confidential information is protected.³⁰⁸
- Contract execution with the utilities – Within three business days of Commission approval of the procurement results, utilities and winning bidders sign binding contractual arrangements using the standard form contracts.³⁰⁹

Unless specifically noted in the following sections, the IPA proposes that the competitive procurements for RECs described in this draft Second Revised Plan follow these past practices that have been refined over the past ten years.

5.3.1. Contracts

For the competitive procurements conducted pursuant to the Initial Plan (as well as the Initial Forward Procurements), the Agency updated its REC contract used in previous competitive procurements for renewable energy credits (other than the Supplemental Photovoltaic Procurements, which featured the Agency as a counterparty rather than the utilities and followed a simplified structure). This update made changes to ensure that the contract was compliant with new requirements found in P.A. 99-0906, but otherwise followed the standard format of a Cover Sheet, Revisions to the Master REC Agreement, and the Master REC Agreement itself.

In the First Revised Plan, the Agency proposed significant revisions to the REC delivery contract structure utilized in competitive procurement events, including integrating what had been three separate sections of the contract into a single, more streamlined contract instrument. This revised contract was utilized in the March 2021 Subsequent Forward Procurement. **In this draft Second Revised Plan, the Agency is not proposing any additional updates to that recently-developed REC delivery contract (subject to other comments received), but is open to stakeholder feedback as to any changes that could increase successful participation in competitive procurement events.**

5.4. REC Eligibility

As discussed in Chapter 4, P.A. 99-0906 placed two new-at-the-time conditions on RECs eligible to be used for RPS compliance. First is a locational standard that allows for RECs from facilities located in Illinois to meet the Illinois RPS, and also from facilities located in adjacent states only if those facilities meet the public interest criteria set out in Section 1-75(c)(1)(I). By implication, RECs from states further afield than the states adjacent to Illinois do not qualify for the Illinois RPS. Second, P.A. 99-0906 introduced a new standard related to how generating units recover their costs. This standard

³⁰⁶ See 220 ILCS 5/16-111.5(f).

³⁰⁷ See id.

³⁰⁸ See 220 ILCS 5/16-111.5(h).

³⁰⁹ See 220 ILCS 5/16-111.5(g).

not only prohibits the use of RECs from generating units that recover their costs through state-regulated rates, but also assesses penalties for RECs from systems later found to be non-compliant.³¹⁰

These eligibility requirements require competitive procurements conducted by the IPA to feature additional steps to verify that RECs being procured (and, in most cases, the underlying generating facilities from which they are being procured) are indeed eligible for the Illinois RPS. For Forward Procurements, additional review is now required during the bidder registration process to allow the Procurement Administrator and the Agency to verify information about proposed facilities and if facilities located in the states adjacent to Illinois meet the public interest criteria (for example, see Chapter 4 for more information on how facilities would request this determination). As the Agency is not proposing Spot Procurements through this draft Second Revised Plan, the question of how to screen a facility for Spot Procurements is not addressed herein, but screening RECs for IL RPS eligibility for Spot Procurements would raise perhaps more complex issues than with Forward Procurements given the non-source-specific nature of Spot Procurements and potential participation by aggregators or others who may have acquired RECs through prior transactions.

5.5. Credit Requirements

To ensure that RECs under contract to satisfy a compliance requirement are indeed delivered, the Agency proposes to continue requiring collateral with contracts, with the collateral amount established as a function of contract value. While specific collateral levels are not proposed as part of this draft Second Revised Plan (and have traditionally been determined through the contract development process), the Agency believes that the level of collateral must be low enough to encourage participation (especially from small businesses and other newer market entrants) and high enough to discourage suppliers from voluntarily defaulting on contracts for economic reasons. **Against the backdrop of higher attrition for competitively bid utility-scale projects than Adjustable Block Program projects across the first years since P.A. 99-0906's enactment, the Agency is interested in stakeholder feedback regarding how best to manage these considerations for future competitive procurement events.**³¹¹

As an initial step, to ensure that entities who participate in procurement events are committed to following through on contract performance, the IPA proposes a strict requirement for any procurements held pursuant to this draft Second Revised Plan that suppliers and associated facilities who voluntarily default on contracts for economic reasons (such as choosing to sell the RECs elsewhere after making the commitment to sell them to an Illinois utility) or misrepresent their eligibility to participate in a procurement event will be barred from participation in future RPS procurements. The Agency will monitor and review this provision and will consider refinements or updates to it in future Plan revisions if necessary.

Similar to the discussion in Sections 6.15.1 and 8.12.1, any forfeiture of collateral by a project under a competitively procured REC contract with a utility will be considered to be returned to the Renewable Resources Budget, and any collateral forfeited by a project under a competitively

³¹⁰ See 20 ILCS 3855/1-75(c)(1)(J). Note that Section 1-75(c)(1)(I) references "facility" and "facilities" for the geographic standard, while Section 1-75(c)(1)(J) references "generating unit" for the cost recovery standard. Section 1-10 of the IPA Act does not specifically define "generating unit" but does define a facility as, "an electric generating unit or a co-generating unit that produces electricity along with related equipment necessary to connect the facility to an electric transmission or distribution system." The Agency understands these terms to be generally interchangeable.

³¹¹ See Section 5.7 below for a discussion of utility-scale project attrition levels.

procured REC contract with the Agency as the Buyer (namely, the Low-Income Community Solar Pilot Projects) will be deposited into the RERF.

5.6. Benchmarks

Prior to the revisions to the RPS contained in Public Act 99-0906, benchmarks used for renewable energy resources procurements (i.e., confidential price levels above which no bids would be accepted) were developed pursuant to a statutory provision requiring that the price paid for renewable energy resources being procured “not exceed benchmarks based on market prices for renewable energy resources in the region,” and required that such benchmarks “be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor” and “subject to Commission review and approval.”³¹²

Through P.A. 99-0906, “cost-effective” now means that the prices for RECs

*do not exceed benchmarks based on market prices for like products in the region. For purposes of this subsection (c), "like products" means contracts for renewable energy credits from the same or substantially similar technology, same or substantially similar vintage (new or existing), the same or substantially similar quantity, and the same or substantially similar contract length and structure. Benchmarks shall be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval. If price benchmarks for like products in the region are not available, the procurement administrator shall establish price benchmarks based on publicly available data on regional technology costs and expected current and future regional energy prices.*³¹³

Due to the sensitive nature of the benchmark development process and how the release of information related to the level of the benchmark could impact bidder behavior in competitive procurements, additional information will not be provided regarding the process for developing the benchmark or any range of potential benchmark prices.

By law, these benchmarks are not to be used to curtail or otherwise reduce contractual obligations entered into by or through the Agency prior to June 1, 2017.³¹⁴

5.7. Procurements for RECs from New Projects vs. RECs to Meet Annual Goals

Section 1-75(c)(1)(F) creates a prioritization order for REC procurements, to the extent that the “budget” of utility-collected funds, pursuant to Sections 1-75(c)(1)(E) and 1-75(c)(6) of the Act and Section 16-108(k) of the Public Utilities Act, becomes a binding constraint:

1. RECs under existing contractual obligations;
2. RECs procured through funding for the Illinois Solar for All Program;

³¹² 20 ILCS 3855/1-75(c)(1) repealed effective June 1, 2017.

³¹³ 20 ILCS 3855/1-75(c)(1)(D).

³¹⁴ Id.

3. RECs necessary to comply with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) [of Section 1-75 of the IPA Act];³¹⁵
4. RECs necessary to meet the remaining requirements of this subsection (c).

Chapter 3 describes a substantial gap between the quantity of RECs needed to meet annual percentage RPS goals and the RECs under contract from and pending prior procurements. While the Agency had satisfied the utility-scale new wind and photovoltaic requirements through the 2025-2026 delivery year via RECs from prior procurements, project attrition across utility-scale wind projects leaves the Section 1-75(c)(1)(C) utility-scale 2025 delivery year requirement short of being met (and, while the utility-scale solar requirement is still on track, quantities under contract are less than envisioned in the ICC’s Order approving the IPA’s Initial Plan). Further, the brownfield site photovoltaic procurement met 2020 delivery year targets, but not 2025 targets.

While four wind projects and two scale solar projects have begun delivery, with three additional scale solar projects excepted to begin delivery imminently, other projects have not been energized. Five solar projects have requested energization extensions that will take them into 2022-2023 delivery year, and four solar projects and two wind projects have been removed from the REC portfolio. Table 3-9 summarizes in aggregate the status of RECs from utility-scale projects. The quantities listed are the aggregated contracted amounts by expected annual REC deliveries.

Table 5-1: Utility-Scale REC Portfolio Status

Status	Solar	Wind	Total
Delivering RECs	410,000	2,065,519	2,475,519
Pending Energization	453,820		453,820
Extensions Granted	1,587,478		1,587,478
Total Expected RECs	2,451,298	2,065,519	4,516,817
2025 REC Target	1,200,000	3,000,000	
Removed ³¹⁶	548,702	879,234	1,427,936

As a consequence, additional procurement events will be required to ensure that Section 1-75(c)(1)(C)’s new renewable energy project delivery targets are met. As discussed in Section 5.1, because the IPA’s next long-term planning process would not conclude until early 2024 (and resultant competitive procurement events may not be conducted for approximately six months or more thereafter), this Second Revised Plan—developed by the IPA in 2021, and approved by the ICC in early 2022—is the appropriate planning cycle for proposing competitive procurement events under which applicant new wind and solar projects would begin delivering RECs in the 2025-2026 delivery year.

³¹⁵ The provisions are for 2,000,000 RECs annually from each technology by the end of the 2020-2021 delivery year, 3,000,000 RECs annually from each technology by the end of the 2025-2026 delivery year, and 4,000,000 RECs annually from each technology by the end of the 2030-2031 delivery year.

³¹⁶ “Removed” indicates RECs that were procured in the 2017 and 2018 procurements but will not be delivered because of the projects not meeting energization deadlines and thus have been removed from the RPS REC Portfolio.

Conducting procurements to meet the annual goals found in Section 1-75(c)(1)(B), such as Spot Procurements, would be more problematic, however. First, under Section 1-75(c)(1)(F), those procurements are simply a lower priority than ensuring new wind and new photovoltaic requirements are met. Second, near-term budget constraints do not allow for procuring RECs from qualifying built and existing renewable energy projects for retirement across the years covered by this Second Revised Plan. While the IPA has committed to “work to meet the renewable energy percentage-based procurement goals required by 20 ILCS 3855/1-75(c)(1)(B)” under the Legislative Audit Commission’s recent report, the current RPS budget simply does not allow for layering additional expenditures atop already committed funds for the 2022-2023 and 2023-2024 delivery years—and the Agency’s next plan revision is available for utilizing Spot Procurements or other strategies to meet those percentage-based goals for the delivery years thereafter.³¹⁷

5.8. Procurements Conducted Under the Initial Plan and the First Revised Plan

In the Initial Plan, the Agency proposed a series of procurements as described in Table 5-2 below. As of the release of this draft Second Revised Plan, the First Subsequent Forward Procurement (wind), the Brownfield Site Forward Procurement, and the Photovoltaic Forward Procurements have all been conducted.

The original Brownfield Site Forward Procurement was conducted in the fall of 2018 and did not feature any winning projects. In February of 2019, the Agency sought feedback³¹⁸ from stakeholders and then petitioned the Commission to reopen Docket No. 17-0838 seeking clarification for the authority to reconduct the procurement with certain modifications. Following the Commission’s approval of that request, the second Brownfield Site Forward Procurement was then conducted in spring/early summer 2019 with the Commission approving the results on August 1, 2019. While the specific quantity procurement in the brownfield site procurement was not disclosed given that only two bidders were successful,³¹⁹ the procurement did exceed the statutory target of 40,000 RECs annually by the 2020-2021 delivery year (although such RECs could begin being delivered after that date under the procurement’s contracts), but did not meet the 60,000 REC procurement target for the 2025-26 delivery year.

The Second Subsequent Forward Procurement (new utility-scale wind), Community Renewable Generation Forward Procurement (non-photovoltaic), and the Low-income Community Solar Pilot Project Procurement (part of Illinois Solar for All) were all conducted in the Fall of 2019. Both the Second Subsequent Forward Procurement and the Community Renewable Generation Forward

³¹⁷ In the Initial Plan originally filed with the Commission, the Agency also proposed “spot procurements” to meet the annual RPS percentage goals found in Section 1-75(c)(1)(B) of the Act. That proposal was premised, in part, on the idea that expenditures made in the early delivery years post-P.A. 99-0906 would not interfere with budget availability to support new projects, which would not be energized until years thereafter (instead, those procurements would just reduce an expected refund to customers after May 31, 2021 of unspent funds given the time required before new projects could be energized). However, in its Order approving the Plan, citing “the serious risk Spot Procurements can pose to the budget which may prevent the IPA from meeting its statutory long-term new build requirements,” the Commission granted “various parties’ requests to cancel the Spot Procurements.” Thus, the final Initial Plan did not contain Spot Procurements.

³¹⁸ See <https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/Brownfield-Site-Procurement-Questions-5-Feb-2019-1.pdf>.

³¹⁹ By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other’s selected bid, and thus determine that other bidder’s bid price.

Procurement³²⁰ did not produce any winning projects. Consistent with the Commission’s Order in Docket No. 19-0995,³²¹ the Agency conducted a procurement of RECs from new utility-scale wind projects in the Spring of 2021, however, no bids were selected.³²²

With the completion of these and other prior procurements, the quantitative new wind and new utility-scale photovoltaic REC targets³²³ for the 2020-2021 delivery year and the 2025-2026 delivery year were met through RECs under contract to be delivered. However, as discussed above, subsequent project attrition—projects under contract no longer being developed under those REC delivery contracts—has since dropped the procured quantity of new utility-scale wind RECs below the 2025-2026 target.

³²⁰ The community renewable generation forward procurement was for non-solar community renewable generation, which the Agency anecdotally understands may be a challenging technological and financial proposition given the 2 MW statutory size limit on community renewable generation projects.

³²¹ See Docket No. 19-0995, Final Order dated February 18, 2020 at 17-18.

³²² See Section 5.9.2 for additional information.

³²³ See 20 ILCS 3855/1-75(c)(1)(C)(i) and (ii).

Table 5-2: 2018-2021 Forward Procurements Summary³²⁴

Procurement	Technology	Procurement Date	Delivery Start	Annual REC Target	Annual RECs Procured	Annual Spend \$
First Subsequent Forward	Wind (utility-scale)	Fall 2018	2021-2022	2 million	1.98 million ³²⁵	6.41 million
Brownfield Site Forward ³²⁶	Photovoltaic (brownfield site)	Fall 2018 /Summer 2019 ³²⁷	2021-2022	0.08 million	Quantity not disclosed	Not disclosed
Photovoltaic Forward	Photovoltaic (utility-scale)	Fall 2018	2021-2022	2 million	2 million	9.28 million
Second Subsequent Forward	Wind (utility-scale)	Fall 2019	2021-2022	1 million	0	0
Community Renewable Generation Program Forward	Any non-photovoltaic (with subscribers)	Fall 2019	2021-2022	0.05 million	0	0
Low-Income Community Solar Pilot Project ³²⁸	Photovoltaic (with community participation / subscribers)	Fall 2019	2021-2022	Set on a \$20 million budget	Quantity not disclosed	Not disclosed
Utility-scale Wind Forward Procurement	Wind (utility-scale)	Spring 2021	2023-2024	1 million	0	0

5.9. Competitive Procurements

While the statutory new wind and new utility-scale solar REC targets for 2020-2021 and 2025-2026 were met through procurements conducted to date, subsequent project attrition has resulted in the 2025-2026 targets not on track to be met. Therefore, as discussed further below, the Agency proposes procurements to make up for that attrition.

Additionally, to help make progress toward the annual percentage of load goals of the RPS, the Agency proposes a structure for potential additional Forward Procurements should ongoing analysis and review of available RPS budgets (or future legislative changes that change the rate cap, extend the budgetary roll-over period under Section 16-108(k) of the PUA, etc., assuming such future new law still maintains the authority of this draft Second Revised Plan) suggest that there are sufficient

³²⁴ 15-year REC delivery term from new generating facilities.

³²⁵ As allowed under the procurement rules, the marginal bidder declined an award of 0.02 million RECs which would have represented a very small portion of their RECs bid and thus was not economically feasible.

³²⁶ The procurement had only two winning bidders therefore certain information is not disclosed per previous Commission Orders in order to maintain bidder confidentiality. By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other's selected bid, and thus determine that other bidder's bid price

³²⁷ When originally conducted in 2018, the Brownfield Site Forward Procurement did not procure any RECs and a procurement was conducted a second time in the Summer of 2019.

³²⁸ The procurement had only two winning bidders therefore certain information is not disclosed per previous Commission Orders in order to maintain bidder confidentiality. By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other's selected bid, and thus determine that other bidder's bid price

funds that become available in future years to conduct those procurements, and subject to the prioritization outlined in Chapter 3.

5.9.1. Forward Procurements

At the time the First Revised Plan was filed, the Agency noted that one of the remaining activities approved in the Initial Plan included the Second Subsequent Forward Procurement of 1,000,000 RECs annually from new utility-scale wind projects. No projects were selected from that procurement event. Accordingly, during the process for Commission approval of that Plan, the Agency proposed that it conduct a utility-scale wind procurement in 2020 or 2021 to complete procurement of the 1,000,000 RECs that had been expected from the Fall 2019 utility-scale wind procurement. The Agency noted that the procurement was not dependent upon the identification of additional funds, as the IPA previously factored into its Plan that 1,000,000 RECs annually would have been procured.³²⁹ The Commission approved the Agency's proposal to allocate funds previously budgeted for the rejected Fall 2019 procurement towards a future utility-scale wind REC procurement.³³⁰ Pursuant to the Commission's direction, the Agency conducted a utility-scale wind REC procurement in March 2021 and once again no bids were selected.

Given the funding limitations described in Chapter 3, with the exception of the procurement of 1,000,000 utility-scale wind RECs discussed below and the brownfield-site photovoltaic procurement discussed further below, other Forward Procurements for RECs from new utility-scale wind³³¹ or utility-scale solar projects will not be automatically conducted. Rather, on a biannual basis each spring and fall, the Agency will review RECs under contract to determine if contingency procurements must be conducted to meet statutory new renewable energy project targets. Should available budgets allow for additional Forward Procurements to be conducted and statutory targets require that they be conducted, the Agency will post to its website an announcement of the procurement(s) that includes an analysis of the available funding and the REC targets.

In general, the Agency recommends continuing the requirement from procurements conducted pursuant to the Initial Plan that REC deliveries begin within three years of the procurement event. However, the Agency does recognize that there are a variety of factors that can lead to project delays, including the RTO interconnection process, so the Agency will continue to include extension provisions in contracts.

5.9.2. Additional Competitive Procurements to Meet 2025 Target

As outlined in the sections above, an additional competitive procurement is necessary to ensure that the 2025 delivery year new wind project REC delivery targets are met. Therefore, the Agency recommends conducting a procurement for 1 million RECs delivered annually from new wind projects sometime between mid-2022 and mid-2023. To minimize RPS budget impacts, the earliest REC delivery from this procurement will be for the month of June 2025. **The timing of this**

³²⁹ See Docket No. 19-0995, Final Order dated February 18, 2020 at 15.

³³⁰ Id. at 17.

³³¹ For the purposes of Forward Procurements, the Agency understands that to be considered a "new wind project," a facility must be energized within three years of the Commission's approval of the procurement results. In addition, the Agency notes that it would generally not consider a repowered wind farm a "new wind project" for purposes of Section 1-75(c)(1)(C) of the IPA Act. Providing an incentive for existing generation to simply repower for increased efficiency would be inconsistent with statutory directives encouraging the development of "new" projects to "to diversify Illinois electricity supply, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents" (20 ILCS 3855/1-75(1-5)(6)), as the incremental benefits offered to Illinois residents by a repowered project would be significantly less than those offered by an entirely new facility.

procurement will be informed by stakeholder feedback requested in Section 5.3 above, as feedback received may alter the Agency’s procurement approach and thus necessitate additional time to update the procurement process and contracts.

Additionally, if the Agency receives notice that sufficient levels of attrition will occur across the utility-scale solar projects selected in previously conducted procurements—an unlikely scenario, given observed energization trends and timelines—and thus the RECs expected from these projects will no longer be part of the RPS portfolio to a level that the 2025-2026 REC targets for new utility-scale solar may not be met,³³² the Agency believes conducting an additional procurement contingent on this scenario happening is warranted. As shown in Table 5-3, those previously conducted procurements put the RPS portfolio well ahead of those targets for utility-scale solar, but short of the 2025-2026 target for new wind.

Table 5-3: New Wind and New Utility-Scale Solar RECs Under Contract and Targets

	New Wind	New Utility-Scale Solar³³³
Cumulative Annual RECs Procured after Project Attrition³³⁴	2.065 million	2.451 million
2020-2021 Target	2 million	0.8 million
2025-2026 Target	3 million	1.2 million
2030-2031 Target	4 million	1.6 million

Prior to conducting any Contingency Procurement, the Agency will consult with ICC Staff. The Agency will not seek formal Commission approval for conducting a Contingency Procurement, and will conduct such procurements based on the factors outlined above through the Commission’s approval of this draft Second Revised Plan and the need to meet statutory 2025 delivery year new wind project and new photovoltaic project targets.

5.9.3. Brownfield Site Photovoltaic

In the Initial Plan, the Agency proposed a procurement for RECs from brownfield site photovoltaic projects and included a target of 80,000 RECs delivered annually. As discussed above in Section 5.8, the procurement was initially held in the fall of 2018 in conjunction with the Photovoltaic Forward Procurement and did not successfully procure any RECs. The Agency subsequently issued a request for comments from stakeholders to gain a better understanding of factors that may have contributed to the lack of success of the procurement, and filed a motion with the Commission in March of 2019 for a clarification to provide the authorization to conduct another procurement. The Commission granted that motion on April 26, 2019.

³³² Overall targets for RECs from new solar projects are the same as for new wind; however, 50% of those RECs must come from the Adjustable Block Program, 2% from brownfield site solar (which could also be considered utility-scale if over 2 MW in size), and 40% from utility-scale solar (with 8% not specifically described). Therefore, this Section only considers utility-scale solar, and not other types of solar.

³³³ 40% of overall new solar target.

³³⁴To date four utility-scale solar projects and three utility-scale wind projects have not met project energization deadlines. .

The Agency made certain adjustments to the procurement guidelines (notably around acceptable age of documentation of eligibility) and conducted another procurement on July 26, 2019. On August 1, 2019, the Commission approved the results, which resulted in exceeding the upcoming statutory target of 40,000 RECs delivered annually by 2020-2021. However, the 2025-2026 target of 60,000 RECs was not met.³³⁵ Therefore the Agency recommends conducting a procurement for RECs from Brownfield Site Photovoltaic Projects with the same goal of meeting the target of 80,000 RECs delivered annually (the 2030 brownfield site photovoltaic projects procurement target).

The contract used in 2019 for Brownfield Site Photovoltaic Project procurement included an initial REC delivery deadline of May 31, 2022 with an option to extend that deadline (with additional collateral requirements) to May 31, 2023. The Agency recommends holding this procurement after May 31, 2022 to allow for adjusting the procurement volumes should either or both of the previously selected projects fail to meet the energization date (and not select the extension option). Like the procurement for RECs from new utility-scale wind projects described above, the earliest REC delivery date for this procurement would be June 2025.

5.9.4. Other Renewables Forward Procurement

As contemplated by the Initial Plan (see Section 5.8.3 of the Initial Plan), in June of 2019, the Agency issued a Request for Information to gauge developer and other stakeholder interest in a forward procurement for RECs from new renewable energy resources that are not wind or photovoltaic. The Agency received a very limited response to the Request for Information (only receiving responses from MidAmerican Energy and the Union of Concerned Scientists).³³⁶ Those comments only provided limited information on a few potential projects under development in Iowa (but did not address if they have their costs recovered in rates regulated by a state, which would make them ineligible³³⁷), did not provide any insight into the economics or cost effectiveness of such a procurement, and raised a number of potential concerns related to the environmental impacts of biomass energy projects.

Based on the comments received, and with the concurrence of ICC Staff as described in the Initial Plan, the Agency does not recommend conducting a Forward Procurement for RECs from renewable energy resources that are not wind or photovoltaic. In Docket No. 19-0995 approving the First Revised Plan, no party sought for such a procurement to be conducted.

5.9.5. Community Renewable Generation Program

In the Initial Plan, the Agency proposed a Community Renewable Generation Program Forward Procurement (see Section 5.8.4 of the Initial Plan). This procurement was designed to recognize that while Section 1-75(c)(1)(N) of the IPA Act required the creation of a community renewable generation program, the law provided firm guidance only on how to procure RECs from community solar projects (through the Adjustable Block Program), with other renewable generating technologies unaddressed. The Community Renewable Generation Program Forward Procurement would then create an opportunity for non-photovoltaic community generation projects to be developed. The procurement was conducted in December 2019 and did not yield any selected bids.

³³⁵ There were two selected projects and therefore specific procurement quantities have not been released.

³³⁶ See: <https://www2.illinois.gov/sites/ipa/Pages/Draft-Long-Term-Renewable-Resources-Procurement-Plan-Comments-2019.aspx>.

³³⁷ See 20 ILCS 3855/1-75(c)(1)(I).

While the Agency appreciates the potential opportunities for additional community renewable generation procurements to expand the range and diversity of renewable energy resources in Illinois, due to the current budget constraints, the Agency does not propose another non-photovoltaic community renewable generation procurement in this draft Second Revised Plan. In Docket No. 19-0995 approving the First Revised Plan, no party sought for an additional community renewable generation procurement to be conducted.

5.9.6. Proposed Competitive Procurements

As discussed above in Sections 5.9.2 and 5.9.3 the Agency is proposing to conduct the following competitive procurements during the 2022 and 2023 calendar years to meet the statutory 2025 delivery year REC targets. Consideration of any additional competitive procurements featuring REC deliveries prior to the 2025-2026 deliver year would almost certainly require a change in the current RPS funding structure through legislative action.

Table 5-4: Proposed Procurements

Procurement	Technology	Procurement Date	Delivery Start	Annual REC Target
Wind Forward Procurement	Wind (utility-scale)	2022 or 2023	2025	1 million
Brownfield Site Photovoltaic	Photovoltaic (brownfield)	After May 2022	2025	Up to 80,000

5.10. Wind/Solar Matching Requirement

As discussed in Section 2.4.5, Section 1-75(c)(1)(G)(iv) of the IPA Act requires that the projected amount of RECs procured (annually) from new wind projects not exceed the projected amount of RECs procured from new photovoltaic projects by more than 200,000 RECs, and that should this occur the Agency adjust the procurement plan accordingly.

The new photovoltaic project REC quantities presently under contract include RECs procured through the Adjustable Block Program and the Illinois Solar for All Program. As of the release of this draft Second Revised Plan (inclusive of the volumes that were expected to be procured in the remaining 2019 procurements and the full allocation of the Adjustable Block Program RECs), it appears that new photovoltaic RECs procured exceed new wind RECs procured as shown in Table 5-2.³³⁸ Absent a significant fall off of RECs procured due to projects not being completed and energized, it appears that this matching requirement is not likely to be a significant concern in the near future.

³³⁸ For a more detailed version of this table see Table 3-9.

Table 5-5: New Wind/Solar RECs Expected Deliveries³³⁹

Delivery Year	All Solar RECs	All Wind RECs	Solar In Excess of Wind
2021-2022	2,065,642	2,065,519	123
2022-2023	3,683,702	2,065,519	1,618,183
2023-2024	3,683,499	2,065,519	1,617,980
2024-2025	3,683,298	2,065,519	1,617,779
2025-2026	3,683,105	2,065,519	1,617,586
2026-2027	3,682,896	2,065,519	1,617,377
2027-2028	3,682,697	2,065,519	1,617,178
2028-2029	3,682,500	2,065,519	1,616,981
2029-2030	3,682,297	2,065,519	1,616,778
2030-2031	3,682,111	2,065,519	1,616,592
2031-2032	3,681,910	2,065,519	1,616,391

Nevertheless, to keep this matching requirement from being exceeded, the Agency will assess the balance between RECs procured from new wind and new photovoltaics prior to proposing any additional Contingency Procurements. Should this assessment demonstrate the need to increase photovoltaic procurement quantities or reduce wind procurement quantities, the matching requirement would serve as the basis for adjusting REC procurement volumes, and such volumes would be adjusted to bring RECs under contract in line with the requirements of Section 1-75(c)(1)(G)(iv) of the Act.

5.11. Procurements after 2023

This draft Second Revised Plan covers the Agency’s potential proposed procurements for calendar years 2022 and 2023. Absent legislative changes to available budgets (or other changes to the structure of the Renewable Portfolio Standard), it appears highly unlikely that even expanded REC targets for Forward Procurements will reach the annual percentage-based REC goals of the RPS for the time being. As described in Section 3.18, as initial payments for RECs from the Adjustable Block Program (that is, payments for projects in the blocks authorized by the Initial Plan) are completed in 2024 and 2025, the available annual RPS budget should begin to expand, which could allow for an increase in the scale of future Forward Procurements. However, that budget availability may be constrained by the requirement to meet future REC targets for the Adjustable Block Program.

Procurements to be conducted after 2023 will be considered in the next revised Plan. A draft of that Plan is scheduled for release in the summer of 2023.

³³⁹ This table is based upon procurements held to date and expected energization dates for remaining utility-scale solar and Adjustable Block Program projects currently still under development. It does not account for any proposed procurements contained in this Chapter.

6. Adjustable Block Program

6.1. Background

Sections 1-75(c)(1)(K) and (L) of the IPA Act, as amended by Public Act 99-0906, required the Agency to establish an Adjustable Block Program for the procurement of RECs from new photovoltaic distributed generation systems and from new photovoltaic community renewable generation projects (colloquially known as “community solar”). The Adjustable Block Program stands in contrast to the competitive procurements described in Chapter 5 in that the Program features administratively determined prices for RECs and is open on an ongoing basis (with the caveat as discussed extensively elsewhere in this plan that this is only as funding allows), rather than featuring discrete procurement events with competitively set, pay-as-bid prices.

Prior to the adoption of the Adjustable Block Program model, the development of new photovoltaic distributed generation in Illinois had been supported in other ways. From 1999 to 2015, the Department of Commerce and Economic Opportunity (“DCEO”) offered rebates for photovoltaic projects; these rebates covered up to 25%-30% of the project cost and supported over 1,100 solar PV projects with a total capacity of 13 MW.³⁴⁰ The DCEO rebates were available once per year and the available budget was quickly allocated, leading to uncertainty for installers about whether their projects would or would not receive a rebate in any given year. No funds have been appropriated for the rebate program in recent years.

Additionally, the IPA conducted Supplemental Photovoltaic Procurements in 2015 and 2016 under authority granted by Section 1-56(i) of the IPA Act, and the Agency proposed and conducted Distributed Generation procurements for the utilities from 2015 through 2017 (although these procurements for the utilities were not limited to photovoltaic systems or to new systems) to meet a statutory DG procurement target in the pre-P.A. 99-0906 RPS. The previous procurements administered by the IPA featured competitive bidding for projects, and each winning bidder received a contract through which RECs actually delivered were paid for at the bidder’s bid price. While this approach created the market efficiency inherent in competitive bidding processes, installers of projects found it difficult to sell projects when the potential REC revenue would not be known until a bid was accepted (or alternatively there would be no REC revenue if a bid was not accepted). To mitigate that challenge, the Agency allowed bidders to bid on forecasted blocks of RECs for systems below 25 kW and give developers time to identify projects using a known REC price.

The Adjustable Block Program is intended to address these issues by featuring an approach that is open on an ongoing basis, rather than relying on specific procurement events (or rebate application windows), features a clear set of prices, and can tap into a much larger budget. The program also expands this model to accommodate community solar so that homes and businesses that cannot place solar on their property can nonetheless participate in, and benefit from, direct access to renewable energy.

However, as discussed elsewhere in this Chapter, funding limitations have now created long waitlists for distributed generation and community solar projects. Chapter 3 discusses the current status of the RPS budget, how the Agency will review budget availability, under what circumstances new blocks could be opened, and any risks to existing REC delivery contracts.

³⁴⁰ See Renewable Energy, Energy Efficiency, and Coal Resources Development Law of 1997, 20 ILCS 687/6-1 *et seq.*

6.2. Lessons From Other Jurisdictions

Illinois is far from being the first to adopt an approach of administratively-determined incentives or a block program to manage growth of the photovoltaic industry. Experience from other markets can inform best practices for setting prices and program design. Solar photovoltaic power has been a rapidly developing technology in recent years, with rapid price declines and industry growth. This dynamic environment has made it challenging for policymakers to design incentives that ensure healthy growth, without costing taxpayers and ratepayers too much or causing unsustainable “boom and bust” cycles that harm the industry and consumers.

To inform the program design of the Adjustable Block Program as described in the Initial Plan, the Agency’s review and analysis of other programs included relevant experiences from Germany, Spain, California, and particularly Massachusetts and New York.³⁴¹

While the New York and Massachusetts programs are both based on a declining block structure, and pay incentives on a first-come, first-served basis, key design aspects vary. The NY SUN program has 3 regions (Long Island, Con Edison, and Upstate) each with a distinct number of blocks, block sizes and block prices. Incentives are paid in dollars per Watt (capacity), declining differently for each region and sector, except for the residential sector where prices decrease by \$0.10/W across all regions. Like the Illinois Adjustable Block Program, NY SUN pays small systems at the time of energization, whereas commercial projects receive a partial payment upfront with the remainder paid in installments over subsequent years.

The Massachusetts SMART program, which began accepting applications on November 26, 2018, is a 1,600 MW declining block incentive program that provides fixed Base Compensation Rates to qualified generation units.³⁴² To be eligible, generation units must be interconnected by one of three investor owned utility companies in Massachusetts. Capacity available in each utility’s service territory was determined by multiplying 1,600 MW by each distribution company’s percentage share of total statewide distribution load in 2016. Initial Base Compensation Rates were established using the results of a competitive procurement for larger projects (> 1 MW) and were announced on January 11, 2018. Incentive levels decline by prescribed amounts over up to eight blocks per electric distribution utility service territory.

Following the first Capacity Block, SMART program Base Compensation Rates decline by 4% per Capacity Block. Under the SMART program, if a utility is eligible to have fewer Capacity Blocks and elects to do so, it may also establish a steeper rate of decline for Base Compensation Rates, and that rate shall yield an overall rate of decline as if the utility had elected to have eight Capacity Blocks.³⁴³ For four of the five utilities, available blocks for large (over 25 kW) projects from the initial capacity allocation are already filled and for two of the five utilities available blocks from the initial capacity has been filled. Revisions to the utilities’ tariffs which would allow for the opening of additional blocks of capacity are awaiting approval by the Massachusetts Department of Public Utilities.³⁴⁴

³⁴¹ A summary of those other programs is available in Appendix C of the Initial Plan available at: <https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/LTRRPP-Filed-Appendix-C-Review-Other-Programs.pdf>

³⁴² See: <http://masmartsolar.com/>.

³⁴³ For example, Fitchburg Gas & Electric d/b/a Unil elected to have four Capacity Blocks with an 8.8% decline in Base Compensation Rates per Capacity Block.

³⁴⁴ See: <https://masmartsolareversource.powerclerk.com/MvcAccount/Login>.

6.2.1. Managing Initial Demand

Some incentive programs have encountered problems dealing with a large quantity of applications coming in very quickly upon the application window opening. California’s Self Generation Incentive Program (“SGIP”) is a prime example. In 2016, \$40 million of SGIP funding was made available. Applicants filed 658 reservation requests totaling \$181 million in requested incentives in the first 10 minutes following program opening.³⁴⁵ Some applicants were found to be deploying questionable strategies to get their application earlier in line, including filing applications from within the same server network as the application recipient. One vendor volunteered to give up half of its rewarded incentives to avoid litigation. As a result, the California PUC reformed the program to add a number of protections against awards being monopolized by early applicants:³⁴⁶

- Replacing the first-come, first-served system with a lottery in which projects having additional greenhouse gas/grid benefits are assigned priority;
- Making all of the incentive money available on a continuous basis in a declining incentive “step” structure, akin to the California Solar Initiative; and
- Restricting each project developer to a cap of 20 percent of the incentive budget, rather than the previous 40 percent cap that applied to equipment manufacturers

In developing the structure of the Adjustable Block Program, the Agency took into account its review of the experiences of other jurisdictions, what it learned from previous procurements it has administered, and the feedback it received from stakeholders. For issues that are not expressly addressed in the Act, the Agency made policy decisions regarding implementation that it believed will result in a cost effective and successful program, with those decisions then vetted through the Commission’s Plan approval process in Docket Nos. 17-0838 and 19-0995. In some cases, opposing or variant positions taken by other litigants were ultimately agreed to by the Agency or otherwise adopted in the Commission’s orders approving the Initial and First Revised Plans.

6.3. Block Structure

The core of the Adjustable Block Program is the concept of a “block.” The program delineates incentives for various categories of eligible projects using blocks of generation capacity at certain prices per REC levels. The blocks are intended to create a progression from one price level to another based on the response of the market. A strong response from the market will result in a rapid progression to a lower price level, for example, while a weak response could elicit an increase in incentives if it is determined to be necessary. Figures 6-1 and 6-2 in Section 6.4 provide an illustration of how the blocks adjust by price.

Progression from one level to another is triggered by a certain volume of deployment, not by a time-based deadline. This deployment-based design is intended to act as a safety valve in case incentives are set at too high a level, which has been a problem in previous attempts at administratively-determined prices. It can also provide long term certainty by giving an indication of future prices and quantities to all potential market participants.

³⁴⁵ Eric Wesoff, Greentech Media, “Update: Stem’s Response to the California SGIP Subsidy Award Process Imbroglio,” May 16, 2016. <https://www.greentechmedia.com/articles/read/Update-Stems-Response-to-the-California-SGIP-Subsidy-Award-Process-Imbroglio>.

³⁴⁶ Eric Wesoff, Greentech Media, “California PUC Proposes Long-Overdue Reform on SGIP Subsidy,” May 23, 2016. <https://www.greentechmedia.com/articles/read/california-puc-proposes-long-overdue-reform-on-sgip-subsidy>.

The initial target for the Adjustable Block Program was to have 1,000,000 RECs delivered annually by the end of the 2020-2021 delivery year (i.e., May 31, 2021).³⁴⁷ Using a capacity factor of 17%,³⁴⁸ this resulted in approximately 666 MW of new photovoltaic generation. This amount was not intended to be a cap; if funding were available, there would be no barrier to going beyond that level to begin to work toward the statutory goal of an additional 500,000 RECs delivered annually by the end of the 2025-2026 delivery year. However, as discussed in Chapter 3, funding is currently a barrier and is expected to remain so for the next several years. The Agency does not expect to be able to open additional blocks of capacity until those funding limitations are resolved. As discussed in Chapter 3, the Agency could theoretically open new blocks of capacity for the Adjustable Block Program if additional funding is identified, although most observed legislative proposals providing for new funding generally also feature changes to the Program structure addressed through a new plan development process.

In order to achieve 1,000,000 RECs delivered annually by May 31, 2021, the Initial Plan featured a block structure that allocated three blocks per category to meet the statutory target for this program (i.e., 1 million RECs per year by the end of the 2020-2021 delivery year), and included a provision to allocate discretionary capacity (as discussed below) to categories through the opening of a Block 4 for each category determined to warrant additional capacity.

To encourage simplicity, the Agency allocated incentives into two groups by service territory/geographic category, based upon load forecasts contained in Chapter 3.³⁴⁹

- **Group A:** for projects located in the service territories of Ameren Illinois, MidAmerican, Mt. Carmel Public Utility, and rural electric cooperatives and municipal utilities located in MISO.
- **Group B:** for projects located in the service territories of ComEd, and rural electric cooperatives and municipal utilities located in PJM.

Incentive levels, expressed through REC prices, vary by group and are based upon the project's location. While the Program Administrator strives to allocate REC delivery contracts with the electric utility in whose service territory the project is located (where applicable, as the IPA lacks authority to procure REC contracts on behalf of municipal utilities or rural electric cooperatives), in order to allocate RECs proportionately among Ameren Illinois, ComEd, and MidAmerican to meet their RPS obligations, that is not always possible.

In developing the Initial Plan, the Agency also considered creating an additional group or groups for MidAmerican, Mt. Carmel Public Utility, rural electric cooperatives, and municipal utilities. However, given their small share of the load in Illinois, the resulting group or groups would be quite small. By consolidating them into the larger groups, block sizes are more administratively manageable, and prices are more transparent and easily understood. The assignment to Groups of projects in the service territories of Mt. Carmel Public Utility, MidAmerican, and rural electric cooperatives and municipal utilities is intended to approximately match those smaller entities to a larger utility with comparable electric rates.

³⁴⁷ See Chapter 3 for more discussion of this requirement.

³⁴⁸ This figure used in the Initial Plan was an assumed first-year capacity factor (relative to AC-rated nameplate capacity) for a fixed-mount photovoltaic system prior to any degradation over time.

³⁴⁹ The combined allocation for Ameren Illinois and MidAmerican would be 28.53% and the allocation for ComEd would be 71.47%. For simplicity, these were rounded to 30% and 70% for determining the size of blocks for Group A and Group B, respectively.

Within each group, the blocks were divided by the allocations specified in Section 1-75(c)(1)(K) of the Act:

- 25% for systems up to 10 kW;
- 25% for systems greater than 10 kW and up to 2,000 kW;
- 25% for photovoltaic community renewable generation; and
- 25% to be allocated by the Agency.

Consistent with the Commission's Order in Docket No. 17-0838, the 25% left to the Agency's discretion was held in reserve, with a reduction in the originally-proposed size of Block 3 used to account for that reduced capacity.³⁵⁰ The Agency subsequently allocated that 25% of capacity to create new Block 4s for certain categories on April 3, 2019.³⁵¹

For systems in the Large DG and Community Solar categories, the use of adjustments (as discussed below in Section 6.5) are used to differentiate the price for RECs from different sized systems.³⁵²

Projects that participate in the Illinois Solar for All Program (as described in Chapter 8) generally follow the program terms and conditions of the Adjustable Block Program, but apply separately to the Illinois Solar for All Program and are not considered part of these Groups and categories for the purpose of filling the capacity of each Block. Illinois Solar for All projects are also subject to additional terms and conditions, as well as a different contractual process.

6.3.1. Block Sizes

In the Initial Plan, the Agency originally proposed a block size structure of blocks of 22 MW for Group A categories, and 52 MW for Group B categories. Pursuant to the Commission's Order in Docket No. 17-0838, Block 3 for each Group/category combination was subsequently reduced to 5.5 and 13 MW respectively to allow the Agency to subsequently allocate the remaining 25% of reserved discretionary capacity. As shown in Table 6-1, on April 3, 2019, the Agency allocated that discretionary capacity through the opening of Block 4 for the Large DG and community solar categories (91.5 MW for Group A – Large DG, 33 MW for Group B – Large DG, 12 MW for Group A – Community Solar, and 30 MW for Group B – Community Solar).

³⁵⁰ See Docket No. 17-0838, Final Order dated April 3, 2018 at 60. That the discretionary capacity is taken only from the third block is evident from the Order's statement that it "adopts the proposal of the Joint Solar Parties to hold 25% of the Adjustable Block Program capacity by megawatt in reserve," as this detail was present in the Joint Solar Parties' proposal, as well as the Order's statement that capacity would be reserved "as outlined in the IPA's BOE."

³⁵¹ See: <http://illinoisabp.com/wp-content/uploads/2019/04/Discretionary-Capacity-Rationale-4.3.19.pdf>.

³⁵² In developing its Initial Plan, the Agency also considered subdividing those categories into smaller blocks; ultimately, the Agency was not convinced that such an approach would be more efficient or a better way to match prices to demand from the market, although it recognizes the resultant imbalance in system sizes across community solar applications (where the vast majority of applications are systems at or near the maximum size despite more lucrative REC prices for smaller community solar projects).

Table 6-1: Initial Plan Block Volumes (MW)

Block Group	Block Category	Block 1	Block 2	Block 3	Block 4
Group A Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives and Municipal Utilities located in MISO)	Small	22	22	5.5	0
	Large	22	22	5.5	91.5
	Community Solar	22	22	5.5	12
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small	52	52	13	0
	Large	52	52	13	33
	Community Solar	52	52	13	30
Total		222	222	55.5	166.5

As of August 16, 2021, all blocks across all Groups and categories are filled and subject to a waitlist as discussed in Section 6.3.3 below.

Prior to opening any new blocks beyond those outlined above (which will likely require identification of additional funding through legislative changes to the RPS funding structure—and assuming such legislative process maintains this planning process, and does not require other changes to program and block structure), the Agency will seek stakeholder comment on whether the block size should be adjusted from the original block sizes (22 MW for Group A, 52 MW for Group B). Assuming sufficient funding is available, one goal of that block size adjustment would be to try to match block sizes with expected annual application volumes, especially for distributed generation projects. The size of new blocks could also depend on the amount of funding that becomes available. The 25% discretionary capacity allocation among project types contemplated by Section 1-75(c)(1)(K)(iv) of the IPA Act would then be determined by the Agency shortly prior to opening a new block, based on program performance, market developments, and stakeholder feedback.

6.3.2. Transition between Blocks

As of the release of this draft Second Revised Plan, all block capacity has been filled and new project applications are being placed on waitlists. This section describes how future transitions between blocks would be managed in the event that additional funding becomes available with this Second Revised Plan still in effect, allowing for the opening of additional blocks.

When a block’s capacity is filled, subject to budget availability, the next block for that category would open at a price expected to be 4% lower than the previous block. For this draft Second Revised Plan, the Agency proposes that when future blocks open after the volume of those blocks is filled (with block volume defined by a measurement of a project being submitted to the program through the payment of the application fee), those blocks would remain open for 7 calendar days. For the closing of those blocks, the capacity of the next block will be adjusted down to account for any capacity

submitted during that 7 day period, assuming funding sufficiency for that additional capacity. The Agency will announce when a block has been filled and when the closing date will be. Opening of new blocks will not be automatic because it will be subject to the identification of available funding.³⁵³

Subject to the conditions outlined above, a project will receive the price of the block that is open at the time the Part I project application is submitted. If a block closes while a project application is being reviewed and the project is not accepted, the capacity associated with that rejected project will be assigned to the next block.

As discussed further in Section 6.15.3 below, should a system in a given block fail to be developed and withdraw from the Program, that system's portion of the block will be forfeited. The volume associated with the forfeited system will be added to the block that is currently open (or, if no block is currently open, the most recently closed block) at the price for that block.

An online dashboard is maintained by the Program Administrator to inform the public of the availability of capacity in each block, as discussed in more detail in Section 6.10.

6.3.3. Managing Waitlists

6.3.3.1. Community Solar

When the Adjustable Block Program opened for project applications in early 2019, 919 community solar projects (representing 1,777 MW of capacity) applied during the initial 14-day application window. After the lotteries held on April 10, 2019 to select projects with applicant capacity significantly exceeding program capacity, 34 projects in Group A and 78 projects in Group B were selected for contracts representing 215 MW of new community solar capacity in Illinois. The remaining 452 community solar projects in Group A (representing 859 MW of capacity) and 355 community solar projects in Group B (representing 703 MW of capacity) were placed on waitlists. Projects are accepted off the waitlist at Block 4 pricing when previously selected projects withdraw from the program (for example, non-development due to prohibitively high interconnection costs) based on the ordinal numbers allocated to each project in that lottery, and subject to available program capacity created by the withdrawn projects. As of the release of this draft Second Revised Plan, seven projects have been selected off the community solar waitlists.

If funding is identified to allow for new blocks of capacity for community solar to be opened (starting with Block 5), project selection for new blocks will combine opportunities for a) selecting currently waitlisted projects and b) selecting from new project applications intended to increase the diversity of areas hosting community solar projects, the business models of projects, and the size of projects—with half of each new block (by capacity) assigned to each of these two project selection categories. This approach was approved by the Commission through its approval of the First Revised Plan in Docket No. 19-0995.³⁵⁴ Should legislation authorizing additional funding prescribe a different approach, the Agency will follow those new provisions.

³⁵³ For Community Solar, waitlisted projects would almost certainly exceed any new block capacity, and thus the process described in Section 6.3.3.1.1 would apply. If waitlisted capacity exceeds the block size for a Distributed Generation block, then the block would be filled by those waitlisted projects up to that capacity limit, and this process would be repeated for the next block or blocks (subject to funding availability to open those blocks).

³⁵⁴ Docket No. 19-0995, Final Order dated February 18, 2020 at 44-46.

6.3.3.1.1. Waitlist for Replacing Lottery-Selected Projects

To replace projects originally selected in the lottery should they withdraw from the program or fail to become energized in a timely manner, the Agency will maintain the existing waitlist and continue to select projects in that ordinal ranking for replacing those original projects. Until the opening of a new Block 5, projects will be selected at Block 4 pricing, but with any small subscriber adder updated through this Plan applied to their pricing while still maintaining the small subscriber commitment made for the lottery.

After the approval of the First Revised Plan, the Agency conducted a process to verify that projects had maintained all applicable land use permits and site control. Through that process, 137 of the 797 waitlisted projects were removed from the waitlist. For this draft Second Revised Plan, the Agency proposes that in order for a project to remain waitlisted, Approved Vendors must provide an attestation from an officer of the company with direct knowledge of the project details to the Program Administrator within 90 days of the approval of this Revised Plan. That attestation must verify that the project has maintained any applicable land use permits and site control (e.g., leases or lease options). This simplified process (provision of an attestation rather than documentation of all permits and site control agreements) is intended to ease the administrative burden on and cost to Approved Vendors.

In comments the Agency received after stakeholder workshops in July of 2021, one stakeholder group suggested requiring a deposit, based on an amount per kilowatt of the project's nameplate capacity, for that project to remain on waitlists. The Agency does not support that approach because of the uncertainty surrounding for how long those deposits would need to be maintained and the possibility that future legislation may prescribe a different approach for selecting waitlisted projects, as well as the degree to which deposits may be less easily manageable for smaller businesses.

6.3.3.1.2. Approach to Opening New Community Solar Blocks

50% of capacity available for opening new community solar blocks will come from the established ordinal waitlist, while the remaining 50% of new community solar block capacity will be reserved for projects whose selection would be in part intended to increase the variety of community solar locations, models, and options in Illinois. In the First Revised Plan, the Agency proposed an approach for selecting more diverse community solar projects. In approving the Agency's proposal in the First Revised Plan, the Commission determined that stakeholder feedback would be a valuable tool to refine the scoring approach and best achieve the goals of increasing the variety of community solar locations, models and options in Illinois.³⁵⁵ The Agency sought stakeholder feedback through a comment process conducted in late 2020 as well as through a workshop and comment process held in June and July of 2021.

Based on stakeholder feedback, the Agency has refined its approach to increasing community solar diversity for this draft Second Revised Plan. The Agency also seeks additional stakeholder feedback through public comments with the goal of further refining this proposal prior to filing this Second Revised Plan for Commission approval. The Agency also recognizes that recent legislative proposals generally contain a slightly different approach to "community-driven community solar," and hopes that any additional feedback received in

³⁵⁵ Docket No. 19-0995, Final Order dated February 18, 2020, at 46.

Plan development will be helpful should the Agency eventually be charged with interpreting that legislative language.

For this new, slightly refined approach to increasing community solar project diversity, the Agency proposes the following approach (for the non-waitlisted portion of new blocks):

- When funding becomes available to open Block 5 (or any subsequent block) for each Group, the Agency will announce the specific block opening date with at least 120 days' notice prior to that opening date.³⁵⁶
- The Agency will then accept new community solar project applications for 120 days after the opening date.³⁵⁷
- If verified new project applications received during the 120-day application window are less than the available capacity (i.e., 50% of the Block capacity), then the remaining capacity would be released for selecting additional projects off of the existing ordinal waitlist.
- If new project applications received during the 120-day application window meet or exceed the available capacity, then project selection will be conducted by scoring projects in the following manner, with projects accepted based on the highest scores:
 - Projects will be sorted into four categories based on the development density of the townships in which they are located.³⁵⁸ The highest density class would get 2 points, the next class 1 points, the third class 0.5 points, and the lowest density class 0 points.
 - Projects developed in response to a site-specific RFP issued by a municipality or community group would be awarded 2 points.
 - **The Agency is interested in stakeholder feedback on this topic. How should the Agency define community group for this purpose? Should the Agency use the definition of community-based organization used for the Illinois Solar for All Program (see Section 8.6.2) or should a different standard be used? Furthermore, are there other types of relationships other than a response to an RFP that would demonstrate sufficient community engagement and involvement?**
 - Projects that commit to only serve subscribers in the same county as the project would be awarded 2 points. If the county population is below 50,000, then subscribers in adjacent counties would also be allowed to meet this commitment.
 - This approach would not preclude the project from enrolling subscribers outside of this commitment area, however those subscribers would not be considered "subscribed shares" for the purpose of calculating REC payments.
 - **The Agency is interested in stakeholder feedback on this topic. How long over the life of a community solar project should this requirement be maintained, and how should subscriber turnover be handled?**
 - Projects under 500 kW (AC) in size would be awarded 2 points. Projects between 500 kW and 1 MW (AC) in size would be awarded 1 point. A project's size will be

³⁵⁶ Community solar project applications will continue to be accepted after the approval of this Revised Plan and prior to the opening of Block 5; they will be placed at the end of the current waitlist.

³⁵⁷ A project currently on the existing ordinal waitlist may be withdrawn from that waitlist and resubmitted as a new project application (subject to payment of the application fee) to be considered for these new project selection criteria.

³⁵⁸ For determining the development density category, the Agency proposes to adopt

determined through including any actual or proposed co-located community solar projects in that size determination.

- Projects that do not take agricultural land out of production will receive 1 point.
- Random selection will only be utilized as a tie-breaker for equally scored projects to fill available capacity, if any; however, should the capacity available be so small so as to only accommodate one or more projects below a certain size, then the Agency may only consider those projects small enough to not exceed that remaining capacity.

The Agency proposes this selection criteria with the goal of developing community solar projects based on interest within that project's relevant community. **To avoid selection of a project that does not have community-based support, the Agency proposes requiring a minimum score of 2 points, but the Agency is interested in stakeholder feedback on this requirement: are there ways of ensuring sufficient community support for all projects selected through this process? If an insufficient amount of project capacity qualifies during the initial application window, should the program then open up on a first-come first-serve basis for projects that score at least 2 points? Or should some other prioritization of this capacity be considered (e.g., releasing it to waitlisted community solar projects)?**

The Agency continues to believe that a signed interconnection agreement is an appropriate threshold for project maturity for the purposes of accepting project applications. However, given the long timelines for this specific project selection process, the need to provide a deposit to the utility after signing the interconnection agreement could provide a deterrent to project applications and a driver of additional financial risks. The Agency welcomes comments on alternative project maturity standards that could be used in this limited case.

Projects not selected for an open block will be given the option to be considered for the next block that opens, but will not be given prioritization over new applications. Project scores and new waitlists specific to this scoring-based application pathway will be maintained to replace any capacity (at the applicable block REC price) that becomes available if selected projects withdraw or are not completed. This new waitlist would be treated separately from the current ordinal waitlist. New project applications or replacement projects taken from this second, new waitlist must be equal to or smaller in size than the project being replaced.

As described above, this updated proposal reflects the Agency's consideration of stakeholder feedback.

6.3.3.2. Distributed Generation

As all available capacity for Small and Large DG has been filled, the Agency proposes to continue accepting project applications and placing those projects on waitlists for each Group/Category on a first come/first served basis, with waitlisted projects being processed for ICC approval only as newly opened capacity is created by either earlier submitted projects not being approved or by previously approved projects withdrawing from the program. Projects will be taken from the top of the waitlist at Block 4 pricing (Large DG) or Block 3 pricing (Small DG). A project's place on a waitlist will be confirmed only when the application fee for the project has been paid.³⁵⁹ When new blocks of capacity

³⁵⁹ This approach is intended to be consistent with the approach contained in the ABP Guidebook as of June 2021. See pages 7-9 of the latest version (6/4/21) at: <https://illinoisabp.com/wp-content/uploads/2021/06/ABP-Program-Guidebook-Final-6.4.21-2.pdf>.

are opened, projects on the waitlist at that time would then be placed into the next block or blocks of capacity in the waitlist order at the REC price applicable to that next block.

Should future legislation authorizing additional funding prescribe a different approach to waitlist management, the Agency will follow those provisions.

6.3.3.3. Assignment or Sale of Waitlisted Projects

Projects may be selected off a waitlist in any given Group/category combination either when previously selected and approved projects drop out of the program, thus freeing up program capacity (with the project selected from the waitlist receiving the most recently available REC price), or when a new block of capacity is opened (and receive that block's REC price). While projects on a waitlist are not yet under contract,³⁶⁰ an Approved Vendor may assign that project to another Approved Vendor, or the project itself may be sold, without penalty or impacting the project's position on the waitlist. An Approved Vendor must promptly notify the Program Administrator³⁶¹ of that transfer and provide appropriate documentation.

6.4. REC Pricing Model

For the Initial Plan, the IPA adopted and modified the National Renewable Energy Laboratory's Cost of Renewable Energy Spreadsheet Tool ("CREST") to develop a model for calculating REC prices. CREST is an economic cash flow model that estimates the cost of energy in terms of cents per kilowatt hour associated with specific input assumptions regarding technology type, location, system capital and operating costs, expected production, project useful life, and various project financing variables. The Agency's REC pricing model established initial pricing for each block, with prices then declining 4% for each subsequent block.

In its Order approving the First Revised Plan, the Commission stated that "REC prices must be lower," although it neglected to adopt any specific proposal for how to lower such prices (and no methodology for lowering prices was introduced into the record). Instead, the Commission required that "workshops should be held and stakeholder input considered" regarding how REC prices could be lowered, with a need to be mindful that, going forward, "the IPA must recognize market signals rather than solely relying on its cost modeling approach" in determining REC prices. Any changes to REC prices resulting from that process preceding the next Plan update would be authorized under the IPA's Section 1-75(c)(1)(M) authority to make price modifications "that do not deviate from the Commission's approved value by more than 25%" without Commission review and approval.³⁶²

The Agency solicited stakeholder feedback on REC pricing in November 2020³⁶³ and further feedback after a workshop in July 2021.³⁶⁴ Generally, most stakeholders favored maintaining the 4% decline between blocks, but there was some concern that community solar REC prices remain too high. Alternatively, stated concerns that would argue against a decline in REC prices include the decrease in the Federal Investment Tax Credit from 30% to 26%, a decline in energy prices (which would

³⁶⁰ The allowances in this sentence also apply to a non-waitlisted Part I applicant project that has not yet been selected by the Program Administrator for a REC contract.

³⁶¹ For this Chapter, all references to the Program Administrator refer to the Program Administrator for the Adjustable Block Program. Discussion of the Program Administrator for the Illinois Solar for All Program can be found in Chapter 8.

³⁶² Docket No. 19-0995, Final Order dated February 18, 2020 at 46-47.

³⁶³ See: <https://illinoisabp.com/stakeholder-feedback-rec-pricing-feedback-request/>.

³⁶⁴ See: <https://www2.illinois.gov/sites/ipa/Pages/RenewableResourcesWorkshops.aspx>.

reduce net metering credit value), higher than expected interconnection costs (particularly for community solar), and ongoing uncertainty about the future value of smart inverter rebates.

For the this draft Second Revised Plan, the Agency both offers an example of what REC prices would look like with a continuation of the 4% decline between blocks as well as REC price modeling based upon updating certain inputs to the original pricing model approved in the Initial Plan. **These updated prices should be viewed as a preliminary analysis; the Agency welcomes stakeholder input on the updated modeling and whether the updated assumptions need further refinement. Prior to filing this Second Revised Plan for Commission approval, the Agency will update the model based on stakeholder input and recommend either to maintain the 4% decline or to adopt of a new set of REC prices. If new REC prices are elected, then it is highly likely that the REC prices included in the Plan filed for Commission approval will change from those provided in this draft Plan due to adjustments to the model.**

Table 6-2 contains the REC prices for the Adjustable Block Program based on the 4% decline between blocks. Blocks that have been filled are indicated in grey. The Agency notes that, for Small DG, the opening of the Block 4 would be at a price 11.5% lower than the initial REC prices for Block 1. Alternatively, for Large DG and Community Solar, that price decrease would be 15%.

Table 6-2: Block Group REC Prices, 4% Change Between Blocks (\$/REC)³⁶⁵

Block Group	Block Category		Block 1	Block 2	Block 3	Block 4	Block 5 (if applicable)
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Small	≤10 kW	\$85.10	\$81.70	\$78.43	\$75.29	\$72.28
	Large	>10 - 25 kW	\$78.70	\$75.55	\$72.53	\$69.63	\$66.84
		>25 - 100 kW	\$64.41	\$61.83	\$59.36	\$56.99	\$54.71
		>100 - 200 kW	\$52.54	\$50.44	\$48.42	\$46.48	\$44.62
		>200 - 500 kW	\$46.85	\$44.98	\$43.18	\$41.45	\$39.79
		>500 - 2,000 kW	\$43.42	\$41.68	\$40.02	\$38.42	\$36.88
	Community Solar	≤10 kW	\$96.12	\$92.28	\$88.58	\$85.04	\$81.64
		>10 - 25 kW	\$87.07	\$83.59	\$80.24	\$77.03	\$73.95
		>25 - 100 kW	\$70.95	\$68.11	\$65.39	\$62.77	\$60.26
		>100 - 200 kW	\$60.47	\$58.05	\$55.73	\$53.50	\$51.36
		>200 - 500 kW	\$55.46	\$53.24	\$51.11	\$49.07	\$47.10
		>500 - 2,000 kW	\$52.28	\$50.19	\$48.18	\$46.25	\$44.40
		Co-located systems exceeding 2 MW in aggregate size	\$47.03	\$45.15	\$43.34	\$41.61	\$39.94
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small	≤10 kW	\$72.97	\$70.05	\$67.25	\$64.56	\$61.98
	Large	>10 - 25 kW	\$73.23	\$70.30	\$67.49	\$64.79	\$62.20
		>25 - 100 kW	\$65.61	\$62.99	\$60.47	\$58.05	\$55.73
		>100 - 200 kW	\$53.75	\$51.60	\$49.54	\$47.56	\$45.66
		>200 - 500 kW	\$48.07	\$46.15	\$44.30	\$42.53	\$40.83
		>500 - 2,000 kW	\$44.64	\$42.85	\$41.14	\$39.49	\$37.91
	Community Solar	≤10 kW	\$91.89	\$88.21	\$84.69	\$81.30	\$78.05
		>10 - 25 kW	\$82.82	\$79.51	\$76.33	\$73.28	\$70.35
		>25 - 100 kW	\$66.65	\$63.98	\$61.42	\$58.96	\$56.60
		>100 - 200 kW	\$56.12	\$53.88	\$51.72	\$49.65	\$47.67
		>200 - 500 kW	\$51.09	\$49.05	\$47.08	\$45.20	\$43.39
		>500 - 2,000 kW	\$47.88	\$45.96	\$44.13	\$42.36	\$40.67
		Co-located systems exceeding 2 MW in aggregate size	\$42.59	\$40.89	\$39.25	\$37.68	\$36.17

As part of the development of this draft Second Revised Plan the Agency undertook the exercise of updating the REC Pricing Model with the following changes:

- Adjusted the Federal Investment Tax Credit to 26%
- Updated project cost information based on the *U.S. Solar Photovoltaic System and*

³⁶⁵ In the “Large” and “Community Solar” categories the prices listed include the Size Category Adjustments described in Section 6.5.1.

*Energy Storage Cost Benchmark: Q1 2020 Report from NREL.*³⁶⁶ This also includes reducing the impact of tariffs on imported modules to the current level.

- Updated the AC/DC ratios based on an analysis of actual project applications received and energized and capacity factors based on PVWatts analyses of energized projects. However, due to the lack of Community Solar projects below 500 kW, for smaller community solar size categories, DG project data was utilized.
- Updated net metering credit values and energy values to current values.
- Updated Community Solar interconnection costs based on a survey of Approved Vendors with actual interconnection costs for energized Community Solar projects.

A description of the updated REC Pricing Model and inputs used is contained in Appendix D and updated REC Pricing Spreadsheets are provided in Appendix E. **The Agency encourages stakeholders to review these Appendices and provide comments on them as part of the feedback on this draft Second Revised Plan.**

While many of the resulting REC prices shown below are similar to the prices resultant from continuing the 4% price decline, there are several key differences:

- REC prices for DG are higher. Key factors for this change include the decrease in the ITC from 30% to 26% and higher AC/DC ratios (the original model used 75% across the board the updated analysis has a range from 77 to 85%). In addition, the updated PVWatts analysis of capacity factor has increased variation between group and size categories (the original model a 14% DC capacity factor for all DG projects, this updated model has a range from 13.45% to 15.3%). The lowest capacity factors are seen in Group B Small DG and Large DG between 10 and 25 kW and are reflected in the higher modeled REC prices for those size categories.
 - **For this draft Second Revised Plan, the Agency is particularly interested in stakeholder feedback on the capacity factors used. Stakeholders should note that, due to the nature of the CREST model used as part of the REC Pricing model, its capacity factors are DC capacity factors, and not the AC capacity factors used to calculate REC delivery quantities.**
- REC prices for smaller size community solar projects are higher. This is due to the lack of actual capacity factors for smaller sized community solar projects and instead the use of capacity factors from comparably sized DG projects as a proxy, as well as the higher interconnection cost estimates (which are scaled to the size of the project but based on the larger community solar projects that have been approved and energized).
 - **The Agency is interested in stakeholder feedback on if these are the correct proxies. They may reflect that smaller community solar projects are more likely to be roof-mounted and thus share more characteristics with DG projects. These higher REC prices could help offset the higher development costs associated with smaller community solar projects in more urbanized areas. But if smaller projects are ground-mounted systems that are just scaled down versions of the 2 MW community solar project model (e.g., use trackers rather than fixed mount), then using the**

³⁶⁶ See: <https://www.nrel.gov/docs/fy21osti/77324.pdf>. This was report was released in January 2021 and is the most recent data available from NREL

same capacity factor as 500 kW to 2 MW community solar projects would be appropriate, and REC prices would be lower.

- REC Prices for 500 kw to 2 MW and co-located community solar projects are slightly lower. Higher capacity factors (17.779% for Group A and 17.415% for Group B compared to the 16.5% used in the initial model) have offset higher interconnection costs (\$434,671 in Group A and \$618,410 in Group B compared to \$279,045 in the original model for a 2 MW AC project) and the decline in the ITC.
 - **For this draft Second Revised Plan, the Agency is interested in stakeholder feedback on the capacity factor and the interconnection costs. The interconnection cost estimates were based on a survey of Approved Vendor with energized community solar projects, and thus was a limited data set that may not be reflective of interconnection costs more generally.**

The REC Pricing Model is a very complex model with many inputs and significant interactive effects between them. The changes in REC prices that resulted from updating of the model inputs reflect that complexity. **The Agency is very interested in stakeholder feedback on the model and its inputs, and expects that through comments on this draft Second Revised Plan, many of those inputs may be updated prior to filing the Second Revised Plan for Commission approval. Therefore, these prices should be viewed as preliminary in nature and could change significantly as this process continues. Examples of inputs that were not updated include financing structure (e.g., debt ratios and project financing interest rates), internal rates of return, and O&M costs. These inputs are all listed in detail in Appendices D and E.**

The Agency will also hold a workshop at 1pm Central Time on September 15, 2021 to explain in greater detail the REC Pricing model and input assumptions. This workshop will include a walk-through of the REC Pricing Model spreadsheet and demonstrate how changing input assumptions impacts the resulting REC price output. Please note that this workshop will be for educational purposes only and not for taking comments on this draft Second Revised Plan.³⁶⁷ Comments on the draft Second Revised Plan must be submitted through the processes described in Section 2.2.7.

³⁶⁷ This workshop will be accessible at: <https://zoom.us/j/91530370732?pwd=VXhoS2x5TzB5Y0sreHlvWHpodzY3OT09>. or by phone at 312/626-6799;; Meeting ID: 915 3037 0732; Passcode: 5126923285.

Table 6-3: Updated REC Prices, Preliminary REC Pricing Model Update (\$/REC)

Block Group	Block Category		Next Block	Difference from Current Scheduled Next Block
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Small	≤10 kW	\$90.39	120%
	Large	>10 - 25 kW	\$82.90	124%
		>25 - 100 kW	\$65.83	120%
		>100 - 200 kW	\$53.06	119%
		>200 - 500 kW	\$47.12	118%
		>500 - 2,000 kW	\$45.71	124%
	Community Solar	≤10 kW	\$104.18	128%
		>10 - 25 kW	\$95.09	129%
		>25 - 100 kW	\$78.13	130%
		>100 - 200 kW	\$68.22	133%
		>200 - 500 kW	\$63.47	135%
		>500 - 2,000 kW	\$39.08	88%
		Co-located systems exceeding 2 MW in aggregate size	\$32.56	82%
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small	≤10 kW	\$90.26	140%
	Large	>10 - 25 kW	\$90.68	146%
		>25 - 100 kW	\$77.46	139%
		>100 - 200 kW	\$61.01	134%
		>200 - 500 kW	\$53.95	132%
		>500 - 2,000 kW	\$45.53	120%
	Community Solar	≤10 kW	\$107.45	138%
		>10 - 25 kW	\$99.43	1410%
		>25 - 100 kW	\$79.15	140%
		>100 - 200 kW	\$65.05	136%
		>200 - 500 kW	\$59.79	138%
		>500 - 2,000 kW	\$38.62	95%
		Co-located systems exceeding 2 MW in aggregate size	\$35.43	98%

6.5. Adjustments and Adders

Adjustments and adders are intended to adjust the base REC price to meet specific additional purposes. These include adjusting for system size (accounted for in the prices above), adjusting for the additional costs of small subscribers to community solar, and potentially accounting for the changes to net metering, smart inverter rebates and federal tax credits. Greater detail on issues in the REC pricing model can be found in Appendix D of this draft Second Revised Plan.

While the Act seeks to encourage projects “in diverse locations...not concentrated in a few geographic areas,”³⁶⁸ at this time the Agency is not proposing any specific geographic REC price adders for distributed generation projects. The Agency believes that the split of the blocks between utility service territories adequately addresses program-wide/statewide geographic diversity, and initial DG project applications indicate that projects are well distributed across the state.

The Agency observes that while projects are spread across the state at a high level, community solar projects are predominantly located in rural areas that are not likely to be close to subscribers. As discussed in Section 6.3.3.1, the Agency sought stakeholder feedback as part of the development of the First Revised Plan on how to manage the community solar waitlists, and the First Revised Plan presented a proposal for reserving a portion of new blocks of community solar capacity for projects intended to increase geographic diversity (and, specifically, address the imbalance between rural projects and urban/suburban projects). That proposal has been further revised in this draft Second Revised Plan.

6.5.1. Size Category Adjustments

Within the Large DG and Community Solar categories, REC prices vary based on system size. The Agency has created categories for projects over 10 kW to 25 kW, 25 kW to 100 kW, over 100 kW to 200 kW, over 200 kW to 500 kW, and over 500 kW to 2 MW, with adjustments to REC prices reflecting modeled development costs by size category.

For this draft Second Revised Plan, the Agency is not proposing any changes to these size categories and the resulting categories in REC prices, but welcomes stakeholder feedback on if there should be any changes to these categories.

6.5.2. Co-location of Distributed Generation Systems

For purposes of Adjustable Block Program categories and applicable REC prices, the total capacity of distributed generation systems energized after June 1, 2017 on a single parcel that participate in the Adjustable Block Program are considered a single system.³⁶⁹ (For example, three 100 kW systems at a single parcel will be considered a 300 kW system.) If a system at a single parcel is subsequently expanded, the Agency reserves the right to revise the incentive amounts paid for the subsequent system(s), and to set the incentives based on the total expanded system size rather than just treat the expansion as a separate system. For the purpose of establishing a revised incentive level under these circumstances, the systems’ location would be considered at the parcel level. Exceptions will be made if it can be demonstrated that two projects on one parcel have separate, non-affiliated owners and serve to offset the load of separate, non-affiliated entities on a parcel.

The Agency recognizes that in rural areas of Illinois it is not uncommon for a parcel to have buildings (and thus load to be offset by distributed generation) that serve separate residential and agricultural uses, and will evaluate requests to consider those uses separately for the application of this standard. For this draft Second Revised Plan, the Agency welcomes stakeholder feedback on how criteria for making such evaluations.

³⁶⁸ 20 ILCS 3855/1-75(c)(1)(K).

³⁶⁹ Any system developed under this program would require a separate GATS or M-RETS ID from any system developed through a different program (e.g., the Supplemental Photovoltaic Procurement or the Utility DG procurements) or without programmatic support. This would allow for a clear demarcation between systems and their associated RECs.

Additional discussion of co-location of community solar projects, including the approach to co-location of community solar projects adopted in the Commission’s Final Order in Docket No. 17-0838, is included in Section 7.3. For the purposes of consideration of co-location, distributed generation systems and community solar projects are considered separately and would not impact the size calculation applicable to each other. Furthermore, the Agency’s co-location determinations only apply to projects participating in the Adjustable Block Program and not projects installed outside of the Program (e.g., through previously conducted Agency procurements, receiving DCEO rebates, or developed without incentives).

6.5.3. Community Solar

Community solar projects may face additional costs and feature reduced eligibility for direct energy-related revenues than distributed generation systems. On the revenue side, subscribers to such projects are eligible only for energy-only net metering,³⁷⁰ while on the cost side, there is the cost of acquiring, maintaining, and managing subscribers. The prices for community solar RECs shown above in Table 6-2 reflect those differences..

To ensure that the benefits of solar energy are widely shared by Illinois residents, the Adjustable Block Program offers an additional incentive for community solar projects with a higher level of small subscribers (residential and small commercial customers with subscriptions below 25 kW). To account for additional costs related to small subscribers, the schedule of adders in Table 6-5 below will be available to community solar projects that have minimum levels of small subscribers; these adders would be added to the REC prices shown in Table 6-2. For more discussion of issues related to small subscribers, see Section 7.6.2.

For the First Revised Plan, the Agency proposed to eliminate the Initial Plan’s higher adder for over 75% small subscribers.³⁷¹ This change recognized that the desire to achieve at least 25% small subscriber participation in community solar (as discussed in Section 7.6.1) has been more than met by the community solar projects accepted to date and that the adders may be over-incentivizing small subscriber participation to the detriment of participation of larger subscribers while creating outsized impacts on available funding. After approval of this approach by the Commission, this change was applicable to any new projects selected after the approval of the First Revised Plan, including both waitlisted projects selected to replace projects initially selected in the lottery that withdrew or were not completed, or projects selected in new blocks of capacity. The elimination of the 75% or greater small subscriber adder was not retroactively applied to any projects approved by the Commission prior to the approval of the First Revised Plan.

The Agency proposes to maintain this approach of incenting small subscriber acquisition only up to 50% of project capacity for this draft Second Revised Plan. While comments received after the July 2021 stakeholder workshop revealed no consensus as to whether these adders should be further adjusted, the Agency is highly interested in feedback on whether adder levels should be adjusted. The Agency encourages additional comments on this topic, particularly any data from other states about the actual cost of acquiring and managing small

³⁷⁰ 220 ILCS 5/16-107.5(l)(2). The IPA also notes that in the proceeding to approve ComEd’s proposed community solar net metering tariff pursuant to Section 16-107.5(l-5) of the PUA, several parties argued that volumetric transmission charges should be part of the net metering supply credit granted to community solar projects, while ComEd argued that transmission charges should be excluded. The Commission determined that the transmission services charge should be excluded from the community solar net metering credit. Docket No. 17-0350, Final Order dated September 27, 2017 at 15.

³⁷¹ The Initial Plan included a “Greater than 75% small subscriber” adder of \$33.51 for Group A and \$32.65 for Group B.

subscribers. The Agency notes that 93% of the capacity of the 38 community solar projects energized to date is taken up by small subscribers. This is well over the 75% level that the Initial Plan specified for the maximum small subscriber adder, suggesting that the added cost of customer acquisition for small subscribers is outweighed by other factors (for example, the challenges inherent in ARES community solar net metering for larger customers), and thus need not be so heavily incented.

Table 6-4: Current Community Solar Adders

Adder	\$/REC	
	Group A	Group B
Less than 25% small subscriber	No adder	No adder
25% or greater small subscriber and less than 50% small subscriber	\$11.17	\$10.88
50% or greater small subscriber	\$22.34	\$21.77

These adders reflect an analysis of community solar subscription costs contained in the Initial Plan. The Agency notes that a 2018 GTM Research report³⁷² contained estimates of subscriber acquisition costs that ranged from \$0.06 to \$0.25 per Watt and ongoing subscriber management (including billing and replacing subscribers) of \$0.12 to \$0.35 per Watt. The low end of the combined costs from those estimates would be \$0.18 per Watt and the high end \$0.60 per Watt. Translating those costs to the REC output over 15 years of a typical 2 MW community solar project (with a 22% AC capacity factor), those ranges would imply additional subscriber-related costs of \$6.85 to \$22.83 per REC, which indicates that the current small subscriber adders may be too high, especially if the prior adder for systems with greater than 75% small subscriber participation were to be maintained.

Another data point suggesting a lower adder comes from Minnesota, which utilized the equivalent of \$15/REC for a two-year pilot for projects that energized in 2019 or 2020 (and is currently undergoing review with stakeholders advocating for its extension).³⁷³

For this draft Second Revised Plan, the Agency seeks stakeholder feedback on if small subscriber adders should be reduced. The shift to online marketing and enrolment is likely an additional cost savings for community solar providers that may not be reflected in the current adder. To elicit feedback on this topic, and in lieu of additional data or cost modeling, the Agency suggests starting with the midpoint of the range of costs reported by GTRM Research, or \$14.82/REC for 50% or over small subscriber levels. This approach produces adders very similar to the current Minnesota adder.

³⁷² The Vision for U.S. Community Solar: A Roadmap to 2030. GTM Research, July 2018.

³⁷³ See Appendix C for additional information on the Minnesota adder.

Table 6-5: Proposed Community Solar Adders

Adder	\$/REC	
	Group A	Group B
Less than 25% small subscriber	No adder	No adder
25% or greater small subscriber and less than 50% small subscriber	\$7.42	\$7.42
50% or greater small subscriber	\$14.84	\$14.84

These adders would not apply retroactively to projects ICC-approved prior to the approval of this Second Revised Plan, but would apply to any new projects approved after that date (whether taken from a waitlist at current block REC prices or as part of a new block opening).

The calculation of small subscribers for adder purposes shall be based on the percentage of the total energy output of the project subscribed to by small subscribers, and not the number of small subscribers or the percentage or number of subscribed shares. As described in more detail in Sections 6.15.3 and 6.17, a community solar project must demonstrate a level of small subscribers at the time of energization to receive an adder initially, and will have to maintain the small subscriber subscription levels or face having to pay penalties to remove the added value of the adders if the level is not maintained.

The Agency has not proposed an adder that would distinguish between “developer-driven” projects and “community-led” projects. Such a distinction may be difficult to make in practice, may invite opportunities for abuse, and may create additional complexities to program administration. The Agency believes the combination of the Size Category Adjustment, which would provide benefits to smaller projects, plus the option of participating in the Illinois Solar for All low-income community solar sub-program, adequately addresses the needs of those types of projects. For more details on this determination, see Section 7.5.

The issue of the complexity to subscribers of receiving a separate bill from the community solar provider was raised by stakeholders in comments following the July 2021 workshop. Stakeholders made recommendations that the Agency use this Plan to advocate for the adoption of consolidated billing, whereby charges assessed by a community solar provider to its customer could be included on the customer’s utility bill. Regardless of the merits of such a proposal, the Agency does have statutory authority to direct the utilities or the Commission to take action on this proposal. The Agency notes, however, that if consolidated billing is adopted for community solar through a separate regulatory process, it would then be appropriate to adjust the small subscriber adder to reflect the savings that consolidated billing would accrue to community solar providers by not having to provide their own billing and collection services.

6.5.4. Adders to Adjust for Changing System Revenue

As discussed in Section 6.8.1 below, the Agency anticipates that as net metering caps are met, smart inverter rebates are adjusted or created, and the federal Investment Tax Credit decreases, the revenue a system may receive from other sources could decline. If those changes result in such a

decline (and such changes could also *increase* revenue), not accounting for those changes in REC prices could render non-economic a system that would have otherwise been economically viable.

The Agency does not presently propose specific additional adders or adjustments to address these future challenges in this draft Second Revised Plan, but notes that Section 1-75(c)(1)(M) of the Act provides that “[p]rogram modifications to any price, capacity block, or other program element that do not deviate from the Commission’s approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval,” allowing the Agency to make small adjustments to REC prices to account for certain challenges.³⁷⁴ If necessary, the Agency will use this authority to propose adders or adjustments to account for these changes following the process described in Section 6.8, or utilize the Commission approval process for revising its Plan for any larger changes.

6.6. Payment Terms

The Act provides a clear schedule of payments for RECs for projects. Section 1-75(c)(1)(L) specifies the following schedule.

- For systems up to 10 kW, “the renewable energy credit purchase price shall be paid in full by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized.”
- For distributed generation systems greater than 10 kW and up to 2,000 kW and community renewable solar projects, “20 percent of the renewable energy credit purchase price shall be paid by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized. The remaining portion shall be paid ratably over the subsequent 4-year period.”

The Agency has established that the standard for being “energized” as used above must include the completion of the interconnection approval by the local utility and the registration of the system in GATS or M-RETS so that generation data can be tracked and RECs created.³⁷⁵ In addition, as discussed in Section 6.15.4, to avoid a system being completed but RECs not created and delivered, before a system can be considered “energized” so as to initiate the processing of an invoice for REC delivery contract payments, automatic assignment of RECs to the applicable utility must be initiated. The Agency believes that by ensuring proper registration in the tracking system up front, future administrative challenges can be minimized.

For systems over 10 kW and community solar projects, it is not clear from the law how exactly the “subsequent 4-year period” would be calculated, and whether the frequency of payments should be annually, quarterly, or monthly. The Agency proposed in the Initial Plan that after the first payment of 20%, the balance of payments be made on a quarterly basis over the following 16 quarters. For example, if the first payment is made on September 30, 2019 (upon interconnection and

³⁷⁴ The Agency’s June 4, 2018 published prices in its Compliance Filing reflect the “Commission’s approved value” for purposes of subsequent adjustments made by the IPA under this authority. See Docket No. 17-0838, Final Order dated April 3, 2018 at 73-74.

³⁷⁵ This proposed standard is only intended to relate to the contractual payment terms for the Program. Section 1-75(c)(1)(K) specifies that, “[o]nly projects energized on or after June 1, 2017 shall be eligible for the Adjustable Block program.” The Agency views this to mean that a project must be interconnected to the applicable utility after June 1, 2017 and that the registration date of the system in GATS or M-RETS does not impact that determination. The added contractual standard is meant to ensure that energized systems will produce the RECs that they are receiving upfront payments for.

energization), assuming continued compliance with contractual requirements, the next payments would occur approximately on December 31, 2019, March 31, 2020, etc., with the final payment on approximately September 30, 2023—resulting in 17 total payments that bookend a four-year period of time. Payment amounts occur on a set schedule and may be adjusted to reflect changes in REC quantities (per Section 6.16.2), or community solar subscription levels (per Section 6.15.4). Based on feedback received to date, the Agency does not believe that a change to the basic quarterly payment schedule is warranted. However, the refreshed contract structure described in Section 6.7 to be implemented upon new block openings will allow for three separate quarterly delivery schedules to reduce the lag time between a project being approved for payment and the first (or only) payment being received.³⁷⁶

Section 1-75(c)(1)(L) also requires that:

(vi) If, at any time, approved applications for the Adjustable Block program exceed funds collected by the electric utility or would cause the Agency to exceed the limitation described in subparagraph (E) of this paragraph (1) on the amount of renewable energy resources that may be procured, then the Agency shall consider future uncommitted funds to be reserved for these contracts on a first-come, first-served basis, with the delivery of renewable energy credits required beginning at the time that the reserved funds become available.

The Agency will continue to carefully monitor project application approvals and available budgets. As described further in Chapter 3, the Agency determined that obligations could exceed collections starting at the conclusion of the budget rollover period in mid-2021. Nevertheless, aside from waitlisted projects replacing defunct projects as already accounted for in budget modeling, the Agency will not recommend Commission approval of contracts for additional projects if it determines that contract obligations cannot be met through expected funds.

Additional provisions of Section 1-75(c)(1)(L) require that:

- *“The electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation.”*
- *“Each contract shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract.”*

These provisions are discussed further in Section 6.16.

6.7. Contracts

The Agency notes that while payments are made according to the terms described in Section 6.6, the Adjustable Block Program and its REC delivery contracts feature ongoing performance requirements to ensure that RECs are delivered across the 15-year term of the contracts, especially after payments have been made. Section 6.16 describes in more detail how those performance requirements have been implemented.

³⁷⁶ For example, a project approved for payment in January would be on a quarterly schedule of payments occurring in February, May, August, and November; a project approved for payment in February would be on a quarterly schedule of payments occurring in March, June, September, and December; and a project approved for payment in March would be on a quarterly schedule of payments occurring in April, July, October, and January.

The Agency, in consultation with its Program Administrator and its Procurement Administrator, developed a standard REC delivery contract between the utilities and Approved Vendors, much as its Procurement Administrator had done for the competitive procurement processes. This included the opportunity for interested parties to comment on the contract. The original REC delivery contract, reflecting the consensus of the Agency, the utilities, and Commission Staff, was finalized in January 2019, just prior to the opening of the Adjustable Block Program for project applications. Once finalized, that standard REC delivery contract was not subject to further negotiation for each project or batch accepted into the Program.

For the First Revised Plan, the Agency proposed a substantial refresh of the standard delivery contract based upon lessons learned from the execution and early administration of the initial contracts. The Agency conducted stakeholder workshops in 2020 to review the contract structure for the Adjustable Block Program, the Illinois Solar for All Program, and competitive procurements (see Section 5.3.1).³⁷⁷ Key issues that were considered included:

- Shortening and simplifying the REC Contract (and, if possible, synthesizing the contract into a single set of terms and conditions)
- Clarifying contract default versus system default versus penalties
- Clarifying Product Orders, Master Contracts, and Portfolio-level responsibilities
- Termination for convenience (subject to applicable penalties)
- Measurement of community solar subscription levels
- Mechanism of collateral holdbacks³⁷⁸
- Incorporation of Acknowledgement of Assignment forms
- Removal of a project from the contract
- Adoption of a measure providing for mediation by the IPA between utilities and Approved Vendors in certain REC Contract disputes³⁷⁹

Based on the workshops, the Agency worked with the Program Administrator, Procurement Administrator, ICC Staff, and the utilities to develop a draft of a refreshed standard contract and provided stakeholders the opportunity to comment on the refreshed contract. Based on comments received from participants in the process, implementation of the refreshed REC contract was deferred until new blocks can open—which, given current RPS budget constraints, does not appear to be imminent. While the refreshed contract is largely complete, more than one year has past since the last edits to that instrument, and the Agency believes a further round of stakeholder feedback would be appropriate before finalization.³⁸⁰

Once that updated contract is finalized and thus required to be used, Approved Vendors may withdraw projects that had been submitted to the Program before the updated contract's finalization (that are not yet ICC-approved) with no penalty.

³⁷⁷ This process began on April 9, 2020 with the release of a request for stakeholder feedback. See: <https://www2.illinois.gov/sites/ipa/Documents/ABP%20REC%20Contract%20Update%202020/IL%20ABP%20REC%20Contract%20Request%20for%20Comments%209%20APR%202020.pdf>.

³⁷⁸ This topic is discussed further in Section 6.14.6.

³⁷⁹ See Docket No. 19-0995, Final Order dated February 18, 2020 at 49.

³⁸⁰ See: <https://illinoisabp.com/rec-contract/> for the current draft of the revised contract and stakeholder comments. This refreshed ABP REC contract also served as the basis for the contract currently being implemented for the fourth program year of Illinois Solar for All.

As the contract structure will be altered as a result of the above-mentioned process, the Agency recommends that projects approved by the Commission after the contract finalization date would use the new contract, regardless of application date. The Program will also provide an “off-ramp” option for any already-applied projects expecting to be subject to the original contract rendered unable to be developed under the updated contract (although this appears to be unlikely given the nature of modifications found in the updated contract).

Contracts or individual batches (but not individual projects that form a subset of a batch) are assignable. The assignee must agree to, and abide by, the applicable terms and conditions required of an Approved Vendor (or a Single Project Approved Vendor in the case of the assignment of a single project from a contract). Consistent with the Commission’s Order in Docket No. 17-0838, the assignor and the assignee will be required to notify the contracting utility of any assignment, and provide the utility with all pertinent financial, settlement and contact information.³⁸¹ The assignor may be required to pay a fee to the contracting utility. The Agency and its Program Administrator have generated form documents³⁸² for use in accommodating the assignment process and will endeavor to cooperate with the assignor, assignee, and utility in updating Program records to accommodate the assignment.

6.8. Adjustments to Blocks and Prices

The Act contains two provisions that allow the Agency to review and adjust block quantities, sizes, and prices. The provisions are contained in Section 1-75(c)(1)(K):

“The Agency may periodically review its prior decisions establishing the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values, including but not limited to redistributing these amounts and the available funds as necessary and appropriate, subject to Commission approval as part of the periodic plan revision process described in Section 16-111.5 of the Public Utilities Act.”

And in Section 1-75(c)(1)(M):

“If necessary, the Agency may make prospective administrative adjustments to the Adjustable Block program design, such as redistributing available funds or making adjustments to purchase prices as necessary to achieve the goals of this subsection (c). Program modifications to any price, capacity block, or other program element that do not deviate from the Commission’s approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval. Program modifications to any price, capacity block, or other program element that deviate more than 25% from the Commission’s approved value must be approved by the Commission as a long-term plan amendment under Section 16-111.5 of the Public Utilities Act. The Agency shall consider stakeholder feedback when making adjustments to the Adjustable Block design and shall notify stakeholders in advance of any planned changes.”

³⁸¹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 74.

³⁸² See: <https://illinoisabp.com/wp-content/uploads/2019/07/ABP-Acknowledgement-of-Assignment.pdf>; https://illinoisabp.com/wp-content/uploads/2019/10/ABP-Acknowledgement-of-Assignment-and-Consent-2019_10_23.pdf.

In essence, changes of less than 25% to the prices and other program components indicated in the Agency's Commission-approved REC prices can be made by the Agency without seeking review and approval from the Commission, while larger changes will require that review and approval as part of the Agency's regular annual procurement planning process.

The Agency is aware of at least four key events that could significantly impact solar project costs and potentially warrant a new look at REC pricing. First, when a utility reaches its net metering cap (see Section 6.8.1 for more discussion), net metering for new enrollments by residential distributed generation systems will change from full retail net metering to energy-only net metering. Second, upon the net metering cap being met, the distributed generation rebate for smart inverters will change from \$250/kW DC (for non-residential customers and community renewable participants) to a rebate based upon the locational value of the system to the grid, while a new distributed generation rebate will be created for residential customers. Third, the federal Investment Tax Credit stepped down from 30% to 26% for solar projects through 2022, and is presently scheduled to step down to 22% in 2023, then scheduled to be eliminated for residential projects after that time and be reduced to 10% for other projects. And fourth, former President Donald Trump exercised his power under the federal Trade Act to impose import tariffs on crystalline solar photovoltaic panels and modules in January 2018, following an unfair trade practices proceeding at the United States International Trade Commission; the IPA understands that these import tariffs stepped down in February 2020 and again in February 2021 before ending in February 2022.³⁸³ While the IPA's REC Pricing Model has incorporated the projected market effect of those import restrictions,³⁸⁴ there could be further changes to federal trade policy in this area.

Each of these changes could impact the value proposition for developing a project and could require an adjustment in REC prices to keep project development viable or to more properly reflect development costs. The Agency will notify stakeholders and provide opportunities for feedback before instituting any REC pricing changes reflecting these (or similar) developments.

In addition to these factors, and in keeping with the adjustable nature of the Adjustable Block Program, the Agency recognizes that despite its best efforts to set REC (and adder) prices at "just right" levels, it is possible that factors that impact prices may need to be updated to reflect changing market dynamics. In response to very low or very high demand for the program, the Agency may adjust REC and adder prices, block sizes, and other variables as needed to maintain a vigorous and healthy market for distributed solar and to reach programmatic goals. The Agency will monitor program activity and consider changes if so warranted.³⁸⁵

When the Agency becomes aware of a situation that would require a change to block quantities, size, price, or other factors, including, but not limited to, the situations described herein, the Agency will post an announcement to its website regarding the proposed changes and will hold either a stakeholder meeting, or an online webinar to provide an opportunity for stakeholder input, and will proceed mindful of the need for incorporating market feedback into REC prices as outlined by the Commission in its Final Order in Docket No. 19-0995.³⁸⁶ Stakeholders will also be invited to submit

³⁸³ United States International Trade Commission, Investigation No. TA-201-75, Crystalline Silicon Photovoltaic Cells, https://www.usitc.gov/investigations/title_7/2017/crystalline_silicon_photovoltaic_cells_whether_or/safeguard.htm.

³⁸⁴ See Docket No. 17-0838, IPA REC Pricing Model Update of February 27, 2018, at 1-2.

³⁸⁵ The Agency is surveying project developers at the Part II application stage for the actual cost of various system development and installation components.

³⁸⁶ See Docket No. 19-0995, Final Order dated February 18, 2020 at 46-47.

written comments on the proposed material changes which will be posted to the Agency's website. The Agency will consider feedback it receives prior to finalizing changes it makes that are less than 25% and do not require Commission review and approval, and will likewise consider that feedback in filings made before the Commission to update the Adjustable Block Program.

6.8.1. Net Metering Cap Adjustment

Under Section 16-107.5(j) of the PUA, net energy metering is generally credited at a value that accounts for the value of energy and delivery until net metering accounts for 5% of the total peak demand of each electricity provider's eligible customers. At that time, net metering for any new installations will be for energy only.³⁸⁷

When the net metering caps are met, the Agency will review the performance of the program and make price and policy adjustments needed to achieve compliance with RPS goals. As noted above, the Agency could theoretically offset the impact of changes in net metering revenue if those changes would result in less than a 25% change in REC prices. If the necessary REC price change is greater than 25%, then the Agency will seek Commission review and approval of a revised schedule of REC prices as outlined in Sections 1-75(c)(1)(K) and (M) of the Act.

On April 2, 2020, Ameren Illinois notified the Commission that it reached the 3% net metering enrollment level referenced in Section 16-107.6(e) of the PUA (discussed in Section 6.8.2 below). Subsequently, in October 2020, Ameren notified the Commission that it had exceeded the 5% threshold as well. Following an investigation into the tariff which implements Ameren's net metering program, the Commission determined that Ameren's Rider NM – Net Metering incorrectly calculated the 5% threshold and ordered Ameren to amend its tariff in order to comport with Section 16-107.5 of the PUA.³⁸⁸ Under the recently-amended tariff language, Ameren is expected to reach the 5% net metering threshold in early 2023. ComEd likewise notified the Commission that its total generating capacity for net metering customers reached 3% as of December 31, 2020. In response to this notice, and in light of the determination regarding Ameren's net metering tariff, the Commission opened an investigation to determine whether ComEd's Rider POGNM – Parallel Operation of Retail Customer Generating Facilities with Net Metering correctly implements Section 16-107.5(j) of the Act. As of the date of publication of this draft Second Revised Plan, the Commission has not made a determination as to whether Rider POGNM comports with the PUA.³⁸⁹ In a data request response dated June 2019, MidAmerican estimated that the 5% level would be met in 2027.

6.8.2. Smart Inverter Rebate

Under Section 16-107.6(e) of the PUA, when a utility's net metering customers reach total generating capacity equaling 3% of the utility's total peak demand supplied during the previous year, the Commission will initiate an investigation to adjust the smart inverter rebate from \$250/kW DC (for non-residential customers and community renewable participants) to a new value or values (potentially varying based on location), and to establish a smart inverter rebate value or values (again, potentially locationally-based) for residential customers. Once the successor rebate values

³⁸⁷ 220 ILCS 5/16-107.5(j), (n).

³⁸⁸ See Docket No. 20-0738, Final Order dated Dec. 2, 2020 at 39 (appeal pending).

³⁸⁹ See generally, ICC Docket No. 21-0196.

are approved by the Commission, they will take effect when the load of net metering customers for that utility reaches 5% of the total peak demand supplied by the utility during the previous year.

The Commission has initiated an investigation into the value of the successor rebate in the Ameren Illinois service territory; however, the issue remains in active litigation and a determination is not expected for some time, given that Ameren is not expected to reach the 5% threshold until early 2023.³⁹⁰ The Commission has not yet opened an investigation into the value of the successor rebate for the ComEd or MidAmerican service territories. As discussed above, it remains unclear when the 5% level will be reached in the ComEd territory and the 5% level is not expected to be achieved until 2027 in the MidAmerican service territory. Therefore, the Agency is not presently proposing a specific REC price adder to adjust for the change to the inverter rebate (which could also be an increase in the rebate level for some projects, thus not requiring any new adders). The Agency will participate in each utility's investigation proceeding and will consider proposing price adjustments to DG REC prices, if needed, as those investigations proceed. The adoption of any new REC prices as a result of a change to the smart inverter rebate will either follow the process outlined in Section 6.8 or be proposed as part of a Plan update.

6.8.3. Federal Solar Investment Tax Credit Adjustment

The U.S. Congress has set a schedule for a decline and partial phase out of federal tax credits for solar photovoltaics.³⁹¹ Projects that commenced construction in 2017, 2018, and 2019 have received or will receive a 30% Investment Tax Credit; projects that start construction in 2020 through 2022 have received or will receive 26%; and projects that start construction in 2023 will receive 22%, eventually stepping down to 10% for commercial projects and 0% for residential projects.³⁹² After 2015 legislation, project owners who start construction before 2022 may claim the applicable credit once construction begins, as long as the project is operational by the end of 2023.

Additionally, federal tax legislation³⁹³ passed in December 2017 introduced³⁹⁴ a provision called the Base Erosion and Anti-Abuse Tax.³⁹⁴ As discussed in more detail in Section 6.8.3 of the Initial Plan, this provision is widely thought to diminish the value of the Investment Tax Credit for solar generation for many "tax equity" investors, which are often parts of large multinationals.

The phase-out of the federal Investment Tax Credit, and any possible legislative change to that schedule, will affect project economics for distributed solar in Illinois. Like other anticipated changes, the Agency will review the performance of the Program and make price and policy adjustments needed to achieve compliance with RPS goals.

6.8.4. Tariffs on Foreign Photovoltaic Modules and Cells

As discussed extensively in Section 6.8.4 of the Initial Plan, former President Donald Trump issued a Proclamation on January 23, 2018 imposing certain import restrictions, pursuant to his authority under Section 203(a) of the Trade Act, 19 U.S.C. § 2253(a), following a petition brought at the U.S. International Trade Commission by certain American solar component manufacturers alleging that

³⁹⁰ See generally, ICC Docket No. 20-0389.

³⁹¹ Consolidated Appropriations Act of 2016, Public Law 114-113, December 18, 2015, at § 303 (modifying 26 U.S.C. § 48(a)); see also <https://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension>.

³⁹² 26 U.S.C. §§ 48(a)(2)(A), (a)(3)(A)(i), (a)(6)(A).

³⁹³ See Pub. Law 115-97 (Dec. 22, 2017), <https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf>.

³⁹⁴ Id. at § 14401 (adding new 26 U.S.C. § 59A).

imports were entering the United States in such increased quantities as to be a substantial cause of serious injury, or the threat thereof, to the domestic industry.³⁹⁵ The tariffs are set to last for 4 years, starting February 7, 2018 (and thus would expire shortly before the approval of this Second Revised Plan). For solar cells, following the first 2,500 MW of imports in any year, the duty rate is 30% in the first year, then 25% in the second year, then 20%, then 15%. For solar modules, the same annual duty rates apply, without any exemption.

Accordingly, the Agency included a modification to the REC Pricing Model related to the projected market effect of these new import restrictions in its February 27, 2018 REC Pricing Model Update.³⁹⁶ The Commission approved that aspect, *inter alia*, of the February 27, 2018 REC Pricing Model Update.³⁹⁷ The Agency filed its “final” REC prices (i.e., the “Commission’s approved values” for purposes of any Section 1-75(c)(1)(M) adjustments) as a compliance filing with the Illinois Commerce Commission on June 4, 2018, reflecting these and other adjustments.

However, these tariffs have been challenged or may be limited in certain ways. Pursuant to the President’s January 23, 2018 Proclamation, the United States Trade Representative accepted requests for exclusions of particular products during March and April of 2018;³⁹⁸ one result of that process was an exclusion for bifacial solar panels, announced by the Office of the U.S. Trade Representative in June 2019.³⁹⁹ The bifacial panel exclusion was then *reversed* in a decision by the Office of the U.S. Trade Representative in October 2019,⁴⁰⁰ with that decision then blocked by the U.S. Court of International Trade in December 2019,⁴⁰¹ and withdrawn by the U.S. Trade Representative in April 2020.⁴⁰²

Therefore, for this draft Second Revised Plan, the Agency does not include any adjustment for tariffs in the updated REC Pricing Model shown in Table 6-3. However, the Agency will continue to monitor these developments and, if any significant changes to solar component import restrictions occur, will consider making commensurate changes to the REC prices pursuant to its authority under Section 1-75(c)(1)(M) of the IPA Act.

6.9. Approved Vendors

Participation in the Adjustable Block Program takes place through, and is conditional upon, the Approved Vendor process developed by the Agency and implemented by the Program Administrator. The Approved Vendor model was originally based upon the experiences the Agency gained through

³⁹⁵ See <https://ustr.gov/about-us/policy-offices/press-office/press-releases/2018/january/president-trump-approves-relief-us> (January 22, 2018); <https://www.gpo.gov/fdsys/pkg/FR-2018-01-25/pdf/2018-01592.pdf> (January 25, 2018).

³⁹⁶ Docket No. 17-0838, IPA REC Pricing Model Update, February 27, 2018, at 2.

³⁹⁷ Order, Docket No. 17-0838, April 3, 2018, at 74.

³⁹⁸ <https://www.regulations.gov/document?D=USTR-2018-0001-0001>;
<https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=commentDueDate&po=0&dct=PS&D=USTR-2018-0001>.

³⁹⁹ See 84 FR 27684, June 13, 2019, <https://www.federalregister.gov/documents/2019/06/13/2019-12476/exclusion-of-particular-products-from-the-solar-products-safeguard-measure>; see also 83 FR 47393, September 19, 2018, <https://www.federalregister.gov/documents/2018/09/19/2018-20342/exclusion-of-particular-products-from-the-solar-products-safeguard-measure>.

⁴⁰⁰ See [https://ustr.gov/sites/default/files/enforcement/201Investigations/Withdrawal of Bifacial Solar Panels Exclusion to the Solar Products Safeguard Measure.pdf](https://ustr.gov/sites/default/files/enforcement/201Investigations/Withdrawal%20of%20Bifacial%20Solar%20Panels%20Exclusion%20to%20the%20Solar%20Products%20Safeguard%20Measure.pdf).

⁴⁰¹ See <https://www.cit.uscourts.gov/sites/cit/files/19-153.pdf>

⁴⁰² See <https://www.federalregister.gov/documents/2020/04/17/2020-08189/determination-on-the-exclusion-of-bifacial-solar-panels-from-the-safeguard-measure-on-solar-products>.

the development and implementation of the Supplemental Photovoltaic Procurement, as well as observations of programs in other states. While arguably there could be more flexibility available to consumers through a program under which any entity may receive a contract, by having Approved Vendors—i.e., ensuring that any entity receiving a REC delivery contract is registered with and vetted by the Agency, and has met conditions predicate—the Agency is better able to monitor compliance with program terms and conditions, ensure the accuracy and quality of information submitted, and reduce the administrative burden on the contractual counterparties.

This model thus benefits consumers because they can verify that an entity that proposes to develop a photovoltaic system for them (or sell them a subscription to a community solar project) is a legitimate entity participating in the Program. It is important for the Agency to have the ability to monitor the program and ensure high quality performance by the Approved Vendors; an Approved Vendor that fails to live up to the requirements of the Adjustable Block Program could have a significant negative impact on the entire renewable energy market in Illinois that would extend beyond just its own actions. Additionally, as discussed in more detail in Chapter 8, registration as an Adjustable Block Program Approved Vendor is a prerequisite to becoming an Illinois Solar for All Approved Vendor, and the loss or suspension of Approved Vendor status under the Adjustable Block Program would result in an Approved Vendor's status under the Illinois Solar for All Program to also being terminated or suspended.

The Agency does not restrict Approved Vendor participation by entity type; as such, Approved Vendors could include a company that specializes in the aggregation and management of RECs; a for-profit developer or installer of photovoltaic systems; a municipality; or a non-profit serving a specific sector of the community, among others.

Approved Vendors serve as the contractual counterparty with the utility, and thus are the entity that receives payments from the utility for REC deliveries as contract obligations are met.⁴⁰³ Approved Vendors are therefore responsible for submitting necessary paperwork (project applications, status updates, quarterly and annual reports) to the Program Administrator (as the responsible party for the information contained in that paperwork), maintaining collateral requirements (and paying any contractual clawback not covered by posted collateral), and providing ongoing information and reporting. As such, the Approved Vendors must coordinate downstream information from installers/developers as well as individual system owners (who may well provide required information through the installer/developer).

The Agency does not require a specific delegation of duties between the Approved Vendor, sales generating firms, installer/developer, and system owner; rather, it believes that the market is better suited to allow a variety of business arrangements to develop. The key consideration is that the Approved Vendor is ultimately responsible for the fulfillment of contractual obligations, including any obligations delegated to subcontractors, in a manner consistent with the requirements of this Plan, other published program requirements stemming from this Plan (such as those found in the Program Guidebook and Marketing Guidelines), and the Approved Vendor's contract with the counterparty utility.

As discussed in Section 6.9.1, the Agency now requires that Designees (entities working with or on behalf of Approved Vendors for participating projects) be registered with the program. While this

⁴⁰³ The Agency imposes no requirement as to how the Approved Vendor shall share the REC payments with the installer, host, and other project parties.

does not change the responsibilities of the Approved Vendor, or the potential for an Approved Vendor to be held accountable for the conduct of its Designee, the Agency believes that this step provides additional information and transparency to consumers and to the marketplace generally.

Approved Vendors must agree to the following terms:

- Participate in registration and complete any training developed by the Agency
- Abide by these ongoing Program terms and conditions
- Provide information to the Agency on the Approved Vendor's organizational history, capacity, financial information, regulatory status in Illinois and other states (including current complaints or other actions against the Vendor or prior complaints within the past five years), etc.
- **For this draft Second Revised Plan, the Agency proposes that Approved Vendors shall indicate if they are minority, woman, disabled, or veteran-owned, and provide an estimate of the percentage of staff at time of registration and subsequent annual renewals who are women, disabled, veterans, or minorities. This process will include specifying with which certification programs the business has registered.**
- Be registered to do business in Illinois
- Disclose to the Agency names and other information on installers and projects, while otherwise maintaining confidentiality of information
- Document that all installers and other subcontractors comply with applicable local, state, and federal laws and regulations, including for example, maintaining Distributed Generation Installer Certification
- Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers, designees, agents, and affiliates, to the Agency for review, as requested.⁴⁰⁴
- Agree to make changes to marketing materials as instructed by the Agency.⁴⁰⁵
- Register and maintain such registration in GATS or M-RETS and demonstrate the ability to manage project application and REC management functions in the applicable tracking system
- Pay applicable application fees
- Comply with all terms of contracts with utilities under the Program
- Submit Annual Reports on a timely basis

Approved Vendors must renew their approval once a year. Failure by an Approved Vendor to follow the requirements of the Adjustable Block Program, as determined by the Agency and/or its Program Administrator, could result in the entity having the suspension of or losing its status as an Approved Vendor and thus losing the ability to bring new projects into the programs. Losing that status would not relieve an Approved Vendor of its obligations to ensure that RECs from its projects that have been energized continue to be delivered to the applicable utility; failure to meet those contractual obligations could result in having the Vendor's credit collateral drawn upon. (See Section 6.16 for more discussion of contractual obligations.)

⁴⁰⁴ This requirement applies to, at minimum, printed materials, advertising through television and radio, websites (including affiliate websites), web ads, marketing via email or social media, telemarketing scripts, and leads purchased through lead-generation vendors.

⁴⁰⁵ This requirement is not meant to impede the ability to market to customers, but rather to ensure that any types of marketing are not deceptive, confusing, or misleading. Likewise, the Agency is concerned about misrepresentations that could be made about the relationship between an Approved Vendor (or the subcontractors/installers) and the Agency or program.

The Agency recognizes that there may be certain projects where the Approved Vendor model may not be completely appropriate, and therefore allows an Approved Vendor who has only one project to apply under a more limited set of requirements as a Single Project Approved Vendor. Specifically, this designation may apply to a project that is owned by that Single Project Approved Vendor (as opposed to a situation where the Approved Vendor is an intermediary between the system developer and/or owner and the contracting utility). In this situation, the following provisions related to Approved Vendors do not apply:

- Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers and affiliates, to the Agency for review, as requested.
- Agree to make changes to marketing materials as instructed by the Agency.

In addition, the consumer protection requirements found Section 6.13 would not apply to the Single Project Approved Vendor for a distributed generation project, but if the project is a community solar system, all applicable community solar consumer protection requirements related to subscribers do apply (including those concerning marketing materials referenced above).

Single Project Approved Vendors will need to request that status prior to submitting the system's Part I application, and the Program Administrator and Agency will review requests to ensure that this process is not used to avoid the more general requirements of this program through the establishment of nominally separate entities. The minimum size for a project submitted by a Single Project Approved Vendor is 100 kW.

The Agency also encourages the hiring of graduates of job training programs (as described in Section 8.10) to work on installations of projects supported by the Adjustable Block Program. The Program Administrator currently requests Approved Vendors to report on the planned usage of job training program graduates as part of the project application process and requires reporting on job trainee hiring as part of the annual reports submitted by each Approved Vendor.

As more trainees become available, the Program Administrator will provide additional information to Approved Vendors to support this goal.

6.9.1. Approved Vendor Designees

In the First Revised Plan, the Agency created a new requirement for Approved Vendor Designees, requiring that designees must register with the program and be listed on the program websites (both www.illinoisabp.com and www.illinoisshines.com) along with the Approved Vendor(s) with whom they are working. Registration also requires the assent of the Approved Vendor(s), and can be withdrawn by an Approved Vendor working with the designee at its discretion, or by the IPA or Program Administrator if the designee is found to have violated program guidelines and is suspended or has its registration terminated. As used herein, by "Designee," the Agency is referring to third-party (i.e., non-Approved Vendor) entities that have direct interaction with end-use customers. This includes, but is not limited to, installers, marketing firms, lead generators, and sales organizations. The Agency reserves the right to add additional categories as needed.

Registration encompasses the Designee's provision of contact information, acknowledgment of the business relationship with the Approved Vendor, and identification of the categories of the consumer-facing services provided. For this draft Second Revised Plan, the Agency proposes that

Designees also indicate if they are minority or female-owned, and provide an estimate of the percentage of staff at time of registration who are females or minorities.

Additionally, a Designee is responsible for acknowledging that it will comply with all Program requirements applicable to installers or marketing agents, as applicable. Since launching the Adjustable Block Program, the Agency has become aware of instances of violation of program guidelines by Approved Vendor Designees that may have been committed without the knowledge or control of the underlying Approved Vendor. Failure by a Designee to comply with applicable requirements could subject the designee to suspension or termination from registration. If the Designee ignores a suspension (or termination) decision made by the Program Administrator and continues its market activity nonetheless, any Approved Vendor that works with the Designee during that period will be subject to discipline. Likewise, Approved Vendors found to be working with entities engaged in the proscribed activities that fail to register will be subject to discipline.

Pursuant to the Commission's Order in Docket No. 19-0995, Approved Vendors and their designees needed to register with the Program by December 10, 2020 to remain in compliance.⁴⁰⁶

The purpose of this requirement is to increase transparency for the program. Potential customers will be able to verify that a company that reaches out to them is actually a program participant registered with the Program (and likewise be able to review if they are listed on the complaint or disciplinary databases). While the Agency had anticipated that smaller installers would work with Approved Vendors that are aggregators it has become clear that sales and marketing of solar includes a variety of different types of organizations and that this variance can create market confusion.

Approved Vendors are responsible for ensuring that their Designees register with the program (which includes an attestation by that Designee that the Designee agrees to abide by program terms and conditions), and Approved Vendors who fail to do so may be subject to disciplinary actions. This includes Designees contracted by or working for other Designees, sometimes referred to as "nested" designees. For example, for an Approved Vendor who has an installer serving as a Designee, and that installer hires a lead generation firm to assist in marketing for customer acquisition purposes, the Approved Vendor is responsible for ensuring that the lead generation firm (in addition to the installer) registers with the program. One possible benefit to Approved Vendors through this system will be that they will know what downstream firms are working with their direct Designees, and they may be able to better monitor those firms' behavior (as the Approved Vendor is ultimately responsible with conformance with program guidelines).

6.10. Program Administrator

Section 1-75(c)(1)(M) of the Act authorizes the Agency to "retain one or more experts or expert consulting firms to develop, administer, implement, operate, and evaluate the Adjustable Block program." The Program Administrator selection process is expressly exempted from the Illinois Procurement Code.⁴⁰⁷ The Agency issued a Request for Qualifications to start the process of selecting a Program Administrator for the Adjustable Block Program on January 18, 2018.⁴⁰⁸ The Request for Qualifications was a means to select qualified bidders who were then invited to respond to a Request

⁴⁰⁶ See Docket No. 19-0995, Final Order dated February 18, 2020 at 56.

⁴⁰⁷ 20 ILCS 3855/1-75(C)(1)(M).

⁴⁰⁸ The Request for Qualifications was posted to the Agency's website, www.illinois.gov/IPA.

for Proposals.⁴⁰⁹ Responses to the Request for Proposals were received on April 13, 2018.⁴¹⁰ After the evaluation of proposals received and consultation with the Staff of the Illinois Commerce Commission, the Agency selected InClima, Inc. (“InClima”) to serve as the Program Administrator for the Adjustable Block Program. The Illinois Commerce Commission formally approved the execution of a contract between the IPA and InClima at its July 12, 2018 Regular Open Meeting.

On July 21, 2021 the Agency issued a new Request for Qualifications for a Program Administrator for the Adjustable Block Program.⁴¹¹ This Request for Qualifications was issued in anticipation of pending legislation that may significantly increase the scope and complexity of the Adjustable Block Program.

The Program Administrator runs the day to day operations of the Adjustable Block Program. This includes, but is not limited to:

- Assisting the Agency with Approved Vendor and designee registration and training
- Developing a Program Guidebook
- Establishing and maintaining an online portal for Approved Vendors to submit projects (including providing technical support to Approved Vendors and designees) and collecting application fees
- Maintaining an online dashboard to show block status
- Reviewing and approving submitted projects
- Preparing contracts for Commission review and utility execution
- Ongoing monitoring of project development status
- Verifying completion of projects and the processing of approvals for payments, as well as conducting on-site inspections for quality assurance purposes
- Reviewing Annual Reports submitted by Approved Vendors
- Providing information for the public including developing a Program brand, and maintaining an online list of Approved Vendors and educational materials related to distributed generation and community solar
- Assisting in workforce development efforts to the extent feasible

For this draft Second Revised Plan, the Agency is proposing that the Program Administrator will establish a mentorship/training program for new Approved Vendors and designees that are minority-owned, woman-owned, veteran-owned, disability-owned or considered a small business with the goal to help those new program participants learn about program requirements and application procedures. The Program Administrator would assign a dedicated staff person to each new Approved Vendor or Designee who qualifies for this program to provide them technical assistance and provide introductions and connections to established entities. The Agency welcomes stakeholder feedback on this proposal and how it can be refined.

Additionally, the Agency is especially interested in increasing participation in the Program by these types of diverse businesses. The Agency is seeking stakeholder feedback particularly on

⁴⁰⁹ This process generally follows the process contained in Section 1-75(a)(1) to (5) that the Agency has used to select its Procurement Administrator and Procurement Planning Consultant.

⁴¹⁰ The Agency also issued a separate Request for Qualifications/Request for Proposals for a dedicated Program Administrator or Administrators for the Illinois Solar for All Program.

⁴¹¹ See: <https://www2.illinois.gov/sites/ipa/Documents/RFQABPPProgramAdministrator2021.pdf>.

how to increase the number of diverse business entities (i.e., minority-owned business, woman-owned business, veteran-owned business, disability-owned business, or small business). Specifically, what are barriers to entry currently observed in the market and how can those barriers be addressed adequately to ensure a more diverse pool of Program participants?

The Program Administrator is authorized to charge fees to Approved Vendors as described in Section 6.14.4 for processing applications. The Program Administrator operates under a contract with the Agency and may also be reimbursed directly by the utilities for a portion of the cost of the services provided to them including, but not limited to, the preparation of contracts and review of Annual Reports.

Program Administrator costs, other than those covered by fees collected directly by the Program Administrator from Approved Vendors, are considered part of the administrative costs discussed in Section 3.17. The Program Administrator may not be an Approved Vendor.

6.11. Program Status

Starting in September 2018, the Program Administrator began releasing draft program documents for stakeholder review. Input from stakeholders received through both workshops and written comments was used to inform the development of final program materials. The Agency and Program Administrator have held additional workshops since program launch and sought written feedback to further revise these materials as necessary. Key documents developed include:

- Approved Vendor Registration Requirements (released October 30, 2018)⁴¹²
- Lottery Procedures (released November 28, 2018)⁴¹³
- Distributed Generation Brochure and Disclosure Forms (released December 27, 2018)⁴¹⁴
- Program Guidebook (released December 31, 2018, with subsequent revisions released)⁴¹⁵
- Standard REC Contract (released January 28, 2019)⁴¹⁶
- Community Solar Disclosure Forms (released January 31, 2019, revised December 8, 2020)⁴¹⁷
- Distributed Generation and Community Solar Marketing Guidelines (released January, 31, 2019, with subsequent revisions released)⁴¹⁸
- Community Solar Brochure (released February 20, 2019)⁴¹⁹
- Guidelines related to marketing during the ongoing COVID-19 pandemic (first issued March 20, 2020 with subsequent revisions and clarifications)⁴²⁰

Approved Vendor registration opened on November 1, 2018 and the Adjustable Block Program officially started taking project applications on January 30, 2019. Since then, and as of August 1, 2021, Approved Vendors (the direct participants serving as counterparties to Illinois utilities under REC

⁴¹² See: <http://illinoisabp.com/wp-content/uploads/2018/10/Final-Approved-Vendor-Requirements-10.30.18.pdf>.

⁴¹³ See: <http://illinoisabp.com/block-1-lottery>.

⁴¹⁴ See: <http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process>.

⁴¹⁵ See: <http://illinoisabp.com/program-guidebook>.

⁴¹⁶ See: <http://illinoisabp.com/rec-contract>.

⁴¹⁷ See: <http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process>.

⁴¹⁸ Id.

⁴¹⁹ Id.

⁴²⁰ See: <https://illinoisabp.com/category/covid-19/>.

contracts, as discussed in Section 6.9) have submitted applications for 30,755 projects. Those applications have resulted in 671 MW of capacity. Initial block capacity is fully subscribed, and all Group/category combinations now have waitlists.

Table 6-6 presents a snapshot of select program statistics as of August 1, 2021.⁴²¹

Table 6-6: Adjustable Block Projects as of August 1, 2021

Project Type	Project Applications	MW
ICC Approved, Energized⁴²²		
Small DG	20,880	145.33
Large DG	2,138	226.68
Community Solar	34	64.15
Total	23,052	436.16
ICC Approved, Not Yet Energized⁴²³		
Small DG	2,673	22.31
Large DG	288	66.51
Community Solar	77	149.34
Total	3,038	237.16
Waitlisted Applications Currently Being Processed for ICC Approval⁴²⁴		
Small DG	3	0.02
Large DG	8	1.96
Community Solar	0	0
Total	11	1.98
Waitlisted Projects⁴²⁵		
Small DG	3,409	23.47
Large DG	591	36.85
Community Solar	659	1,297.81
Total	4,659	1,358.12
Remaining Available Capacity⁴²⁶		
Small DG		0
Large DG		0
Community Solar		0
Total		0
Overall Program Capacity⁴²⁷		
Small DG		167.66
Large DG		294.15
Community Solar		213.49
Total		675.96

⁴²¹ For additional information on REC quantities procured and budgetary commitments, see Chapter 3.

⁴²² This reflects projects that successfully applied to the Program, are included in batches of projects approved by the ICC (see Section 6.14.6), and successfully developed and energized (Part II Verified).

⁴²³ This reflects projects that successfully applied to the Program, are included in batches of projects approved by the ICC (see Section 6.14.6), and are still under development.

⁴²⁴ This reflects projects that have applied to the program, were placed on waitlists due to blocks being closed, and were subsequently accepted off of their waitlist to fill capacity that became available due to other projects not being completed, and then submitted to the ICC for approval.

⁴²⁵ See Section 6.3.3 for a discussion of the community solar and distributed generation waitlists.

⁴²⁶ This reflects capacity available for project applications.

⁴²⁷ Overall program capacity slightly exceeds the planned 666 MW of capacity, due to the policy of accepting the final project in a block and accepting a threshold capacity of projects across the last day of the final block's closing. For example, if a 22MW-capacity block had used up 21 MW and the final project was 2 MW in size, the final block size would be 23 MW.

6.12. Project Requirements

Projects that are eligible for the Adjustable Block Program must meet, at minimum, two sets of requirements. The first relates to the technical aspects of the system itself, and the second to the customer (and additionally to subscribers, in the case of community solar). The purpose of the first set of requirements is to ensure that high-quality systems are installed that will be capable of generating the expected quantity of RECs over the 15-year duration of the contracts. The purpose of the second set of requirements is to ensure consumer protections.

6.12.1. Technical System Requirements

In this Section, the Agency outlines what technical information must to be submitted for each project. These standards apply for both distributed generation and community solar projects. The application process is described in more detail in Section 6.14.

The technical system requirements are as follows:

- Information about the system location, and size, including but not limited to
 - A description of the technical specifications of the main system components including the make and model, manufacturer, number (quantity) of panels, of panels and inverters and meters, array location (roof or ground mount), tilt, orientation
 - Site map or other project details
- Proof of site control and/or host acknowledgement
- Project-specific estimate of REC production during the 15-year delivery term using PV Watts or a similar tool
- For systems over 25 kW, an Interconnection Agreement signed by both the interconnecting utility and the interconnecting customer⁴²⁸
 - **As discussed in Section 6.3.3.1.2, for this Second Revised Plan, the Agency is interested in feedback on specific alternatives to signed interconnection agreements for new community solar applications where there may be a long lead time between project application and selection. The Agency understands that certain stakeholders, particularly the utilities, are interested in alternative indicators of project maturity for community solar projects that may also alleviate pressure on interconnection processes. In Docket No. 19-0995, some stakeholders argued against the inclusion of the interconnection agreement requirement, but suggested no workable alternative indicator of project maturity to replace this requirement. The Agency continues to believe that signed interconnection agreements are an appropriate indicator of project maturity for distributed generation projects above 25 kW.**
- For ground mounted systems over 250 kW, a land use permit, when applicable, from the Authority Having Jurisdiction (“AHJ”) over the project. In the event a land use permit is not applicable, written confirmation from the AHJ that no permit is required must be provided.

⁴²⁸ While the Adjustable Block Program provides for separate categories for systems up to 10 kW, and greater than 10 kW and up to 2,000 kW, for the purposes of the requirements related to each project, the Agency has determined that 25 kW is an appropriate breakpoint between different levels for certain requirements. While most residential systems are below 10 kW, the Agency observed from its Supplemental Photovoltaic Procurements that there can be larger residential systems, particularly in rural areas. 25 kW is a common breakpoint used in programs in other states and is thus adopted by the Agency for these requirements.

- For systems that include a battery, a detailed schematic showing that either only solar generated power can be used to charge the battery or that the battery’s output does not run through the meter used to measure solar output.

In the Initial Plan, the Agency required that “[f]or systems over 25 kW, evidence of having obtained all non-ministerial permits that, according to the commercially reasonable investigation of the Approved Vendor, are necessary to the project at the time of application to the Adjustable Block program.” While the Agency no longer requires this provision (other than as specified above for land use permits), failure to obtain permits is a developer risk and one which the Agency believes likely would not allow for the invoking of force majeure provisions applicable to failing to meet contractual obligations.

For systems that have been energized prior to application, the following information will also be required:

- GATS or M-RETS unit ID⁴²⁹
- Certificate of Completion of Interconnection
- Photographic documentation of the installation

The Agency recognizes that there may be special situations where some portion of these documents may not be available (for example, some rural electric cooperatives and municipal utilities may not have standardized interconnection documents). The Agency will consider alternative documentation to demonstrate completion of interconnection in those situations.

6.12.2. Metering Requirements

In developing the Supplemental Photovoltaic Procurements that took place in 2015 and 2016, the Agency developed a metering standard⁴³⁰ that is now used for the Adjustable Block Program. That standard has been updated to reflect changes in M-RETS metering requirements that harmonize with GATS standards and to clarify the use of inverters with integrated meters. The current standard applicable to systems registered in either PJM-GATS or M-RETS is as follows:

- Systems 25 kW and over must utilize a new meter that meets ANSI C.12 standards. Inverters with integrated ANSI C.12 compliant production meters are allowed with a specification sheet showing this standard has been met. The inverter must be UL-certified and must include either a digital or web-based output display.
- Systems over 10 kW and up to 25 kW in size utilize a meter that meets ANSI C.12 standards. Meters that are refurbished (and certified by the meter supplier) are allowed. Inverters with integrated ANSI C.12 compliant production meters are allowed with a specification sheet showing this standard has been met. The inverter must be UL-certified and must include either a digital or web-based output display.
- Systems of 10 kW in size and below must utilize either a meter that is accurate to +/- 5% (including refurbished and certified meters), or an inverter that is specified by the manufacturer to be accurate to +/-5%. The inverter must be UL-certified and must include either a digital or web-based output display.

⁴²⁹ GATS or M-RETS registration must be complete and unit ID verifiable through GATS or M-RETS public reports.

⁴³⁰ See: <https://www2.illinois.gov/sites/ipa/Documents/IPA-metering-accuracy-standard-5-14-15.pdf>.

In responses to Request for Comments after the Agency's workshops for the development of the Initial Plan,⁴³¹ several commenters suggested allowing production estimates for smaller systems. A production estimate consists of GATS automatically generating RECs for a system based on the system size and engineering modeling of expected kilowatt hour generation. Production estimates do not require the system owner (or aggregator) to provide ongoing data to GATS. While several states do allow production estimates for smaller systems, because production estimates do not require any actual data being transmitted to the tracking system to verify production, production estimates could be problematic as there would be no way to verify the system's ongoing operation. By contrast, a meter read (from either a meter, or an inverter output) only needs to be submitted once per year to GATS. The Agency thus does not allow production estimates for the Adjustable Block Program and the Illinois Solar for All Program.

Given the upfront payments for RECs paired with the 15-year requirement for RECs to be delivered, the Agency believes that receiving actual data on system performance is essential to ensuring the integrity of the RPS, and having meter reads as infrequent as annually (although they could be as frequently as monthly) appropriately balances the need for accurate data and the compliance burdens on the system operators. Therefore, in the Initial Plan required metered output for the generation of RECs, although the use of inverter readings for systems up to 10 kW were continued to be allowed.⁴³² In other words, the metering standard developed for the Supplemental Photovoltaic Procurement was the metering standard for the Adjustable Block Program, with the caveat that meter reads were only required on an annual basis. The Agency understands that as of January 1, 2020, M-RETS no longer required an ANSI C.12 certified revenue quality meter, so the standards previously applicable for projects registered in GATS are now also applicable to projects registered in M-RETS.

Additionally, in Docket No. 17-0838, questions were raised regarding the applicability of these metering standards to DC-based technologies. In its Order approving the Initial Plan, the Commission sought for the IPA to "ensure that its Plan does not inadvertently prohibit participation from systems that do not convert the DC electricity produced to AC electricity," with any resulting resolution to be presented to the Commission "before or in the 2019 Plan update." The IPA thus endeavored to work with stakeholders on solutions for facilitating permissible participation in the Adjustable Block Program from DC-based systems.⁴³³

After approval of the Initial Plan, the Agency communicated regularly with industry stakeholders who were seeking to coordinate and obtain ANSI approval of a new DC metering standard. However, the Agency has not received any subsequent input from such stakeholders and understands that this standard was finalized in of March 2021.⁴³⁴ The Agency has not yet reviewed the applicability or relevance of this standard to its programs and welcomes stakeholder comments on this topic.

⁴³¹ See: <https://www2.illinois.gov/sites/ipa/Pages/Responses6-2017LongTermRenewableResources.aspx>.

⁴³² The Agency notes that while using an inverter rather than a meter may save on installation costs, if the inverter were to suffer a system failure and lose data, no RECs could be created. A meter may be a more reliable way to ensure REC creation.

⁴³³ Final Order, Docket No. 17-0838, April 3, 2018, at 78-79.

⁴³⁴ See: <https://energycentral.com/c/gr/ansi-dc-metering-standard-earned-emerge-alliance>.

6.13. Customer Information Requirements/Consumer Protections

In addition to the information about the technical system information described in Section 6.12.1, Approved Vendors that submit applications for distributed generation projects are required to provide information to the Agency regarding the customer hosting the system and ensure that certain standardized information about the program was provided to that customer.

The purpose of requiring this information is to ensure consumer protections. Installing a photovoltaic system is a significant financial commitment on behalf of that system's host (and potential owner) and a system that has been sold (or leased) to a customer using incorrect, inaccurate, or deceptive information could put the financial security of Illinois residents or businesses at risk and poison the ongoing viability of the solar market in Illinois. In addition, a project that successfully applies to this program stands to receive a financial benefit from the program in the form of a REC delivery contract and by extension from the ratepayers who fund it. Requiring clear and consistent information on the relationship between the end customer, any Designee(s), and the Approved Vendor is critical to ensuring that the fiscal risks and controls of this Program are properly and prudently managed.

These requirements are Program terms and conditions for participation in a state-administered incentive program that provides the opportunity for additional project revenue through REC delivery contracts. In developing these requirements, the Agency recognized that it is not a regulatory agency and does not have jurisdiction over all distributed generation installations or community solar projects across the state. It can, however, create common sense provisions to ensure that entities developing projects seeking to participate in this program—and thus receive state-administered incentive funds—are held to high standards for consumer protection, and enforce those provisions through suspending non-compliant entities from further participation in this state-administered incentive Program. Ultimately, as the Adjustable Block Program is a ratepayer-funded program intended to benefit the state's residents through enhanced ability to participate in the clean energy economy, it is essential to ensure that this Program produces not only project development, but also a transparent, positive experience for system hosts and subscribers.

The information that must be provided to all customers (and such provision documented to the Agency) includes:

- **Contracts:** A copy of the contract for the lease, sale, or financing arrangement of the distributed generation installation. A list of required contract terms (and, in limited cases, specific contract requirements) has been developed by the Agency in conjunction with its Program Administrator, and has been provided to Approved Vendors.⁴³⁵ At a minimum, Approved Vendors may also use model leases and model financing instruments provided by the Solar Energy Industries Association ("SEIA"),⁴³⁶ or other contracts that meet requirements provided by the Agency. While the Agency will not require that a specific contract form be utilized or require the submittal and approval of all contracts, it retains the right to request copies of contracts from Approved Vendors and develop new requirements for contracts, as well as to advise Approved Vendors that contract terms must be altered as a requirement of continued program participation should the Agency discover unreasonable contract terms.

⁴³⁵ See http://illinoisabp.com/wp-content/uploads/2019/01/dg-contract-requirements-2019_01_23.pdf.

⁴³⁶ Solar Energy Industries Association, "Model Leases and PPAs," <https://www.seia.org/research-resources/model-leases-and-ppas>.

- **Disclosure Form:** The Agency, in conjunction with its Program Administrator, developed standard Disclosure Forms to be completed and provided to each program participant prior to contract execution.⁴³⁷ For distributed generation projects, the form includes standard information on the system equipment and components, warranty, installer, and lease or financing structure. The form includes a standardized estimate of the price and performance of the system as installed, including anticipated first year production, expected annual system production decreases, expected overall percentage degradation over the life of the system, a standard forecast for retail electricity prices, a net cash flow analysis, and an internal rate of return of each project. The form also includes a disclosure that cash flows may change if the utility's net metering tariffs or distributed generation rebates change prior to the completion of the system (e.g., the changes that occur when net metering enrollment reaches 5%). The Agency provides standard electricity prices (and other inputs) to be used for these estimates as to allow equivalent comparisons between different offers.

For this draft Second Revised Plan, the Agency proposes to add the following elements to the Distributed Generation disclosure forms: first additional clarity on if the customer will receive the direct benefits of the REC payments, and if so, any fees, terms and conditions that apply; second, if the proposed system includes elements that are not optimally placed (e.g., panels that are not aligned towards southern orientation), that the customer understands and acknowledges that their system's production will be impacted. The Agency appreciates that some customers may be seeking to offset a set amount of load and intentionally specify non-optimally designed systems, but the Agency wants to ensure that customers do not receive systems that do not match their expectations in terms of system production. As each system has a calculated capacity factor, the level of payment for RECs for a given system will reflect the efficiency of the system design.

For community solar subscribers, the form includes similar applicable provisions as well as conform to the provisions listed in Section 7.6.2.⁴³⁸ In its Order approving the First Revised Plan, the Commission provided analysis reinforcing the requirement that every individual subscriber to a community solar project participating in the Adjustable Block Program or ILSFA must receive and execute an individualized standard disclosure form.⁴³⁹ The Agency does not propose revisions to the requirements surrounding community solar disclosure forms at the time of this draft Second Revised Plan.

- **Brochure:** The Agency requires Approved Vendors to distribute a brochure to program participants prior to the execution of the contract with the program participant. These consumer protection brochures are specific to distributed generation or community solar subscriptions and are available in both print and electronic form, and has been prepared by

⁴³⁷ See <https://illinoisabp.com/program-guidelines-disclosure-forms/>.

⁴³⁸ In the responses to the Request for Comments that the Agency issued in June, 2017, several commenters suggested that the Agency consider adopting the standard disclosure forms developed by the SEIA earlier in 2017 (see: <https://www.seia.org/research-resources/solar-transaction-disclosures>). While there may be aspects of those forms that are worth considering, the Agency is concerned that they do not fully capture the information the Agency believes that potential program participants need to have, in particular, standardized comparisons of energy costs. Therefore, the Agency instead developed its own disclosure forms that capture aspects of the SEIA disclosure forms, best practices from other states, as well as addressing the need to standardize energy cost comparisons.

For a general discussion of challenges related to the marketing of solar and consumer protection policies, see Barbara R. Alexander and Janee Briesemeister, "Solar Power on the Roof and in the Neighborhood: Recommendations for Consumer Protection Policies," March 2016 (<http://utilityproject.org/wp-content/uploads/2016/03/Solar-Power-Consumer-Protection-Report-March-2016.pdf>), in particular, Appendix B.

⁴³⁹ See Docket No. 19-0995, Final Order dated February 18, 2020 at 7. In the event that the Commission or another authoritative adjudicatory body determines that an opt-out municipal aggregation may legally include community solar subscription aggregation for a project participating in the Adjustable Block Program or ILSFA, individually executed standard disclosure forms are still required for each individual subscriber.

the Program Administrator and approved by the Agency.⁴⁴⁰ The brochure informs consumers of their rights, procedures for filing complaints, and point to more information on the Program website. The Agency has prepared the brochure in English and Spanish and will consider creating versions in other languages should sufficient demand exist.

Rather than including these materials with the First Revised Plan for filing with the Commission (and thus seeking Commission approval of the specific forms), the Agency sought and received authority from the Commission for the ability to later develop (and modify) its program-related forms and documents, while reserving the ability to draft actual program-related forms and guidelines independent of that approval proceeding.

Approved Vendors must also agree to provide sales and marketing information, including contract prices and sales volumes, to the Agency on a confidential basis. The Agency uses this information for internal purposes to track market progress and provide guidance to Approved Vendors on compliance with its marketing guidelines.

Additionally, the IPA has developed both its Initial Plan and Revised Plans mindful of the state's experience with the retail energy supply market and the marketing and sale of energy-related products. As such, it seeks to tap into the experience and institutional knowledge reflected in the state's conditions applicable to alternative retail electric suppliers. While the Agency recognizes that Approved Vendors will not necessarily be Alternative Retail Electric Suppliers, and thus as Approved Vendors are not governed as a matter of law by the Commission's Rules applicable to ARES, it believes that the Commission's Title 83, Part 412 rules provide a workable blueprint for expectations of Approved Vendors. Thus, as a condition of ongoing approval, for distributed generation systems or community solar subscription shares below 25 kW in size,⁴⁴¹ Approved Vendors are and have been expected to comply with marketing standards generally equivalent to the following sections of Commission-approved rules for marketing practices by alternative retail electric suppliers. (83 Ill. Adm. Code Part 412, Subpart B):

- 412.105(a)-(c)
- 412.110 (a)-(i)
- 412.120
- 412.130
- 412.140 (a)-(b), (d)
- 412.150
- 412.160 (a)-(b), (d)
- 412.170
- 412.180
- 412.210 (applicable only to community solar)
- 412.240 (applicable only to community solar)

The Agency is also aware that changes to requirements applicable to ARES have been made through Public Act 101-0590. The IPA has updated its marketing guidelines⁴⁴² and certain other program

⁴⁴⁰ See <https://illinoisabp.com/program-guidelines-disclosure-forms/>.

⁴⁴¹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 108.

⁴⁴² See <https://illinoisabp.com/program-guidelines-disclosure-forms/>.

requirements to be in line with those new requirements applicable to alternative retail electric suppliers where applicable.

The Part 412 section list above is not an exhaustive guide of all conditions that the Agency may place upon Approved Vendors, and key items referenced elsewhere in Part 412 (including disclosure forms, contract assignability, and green marketing) are addressed separately in this Revised Plan to the extent applicable to Approved Vendors.

Consistent with the Commission's Order in Docket No. 17-0838, the IPA "fully develop[ed] its procurement terms and conditions after the Commission's approval of the Plan and selection of the Program Administrator." To this end, the IPA and its Program Administrator held a series of stakeholder feedback sessions and solicited written stakeholder feedback before producing its Brochure, Disclosure Form, Contract Requirements, Guidelines for Marketing Material and Marketing Behavior, and Program Guidebook. The Agency decided not to seek Commission approval of these specific documents through approval of its First Revised Plan, but reserves the right to do so going forward. For now, the ability to adjust such documents (i.e., to adjust the conditions under which state-administered incentive funding may be available to participants embodied within those documents) based on ongoing market experience without further Commission approval outweighs the certainty associated with having an administrative order from a quasi-adjudicatory body providing fixed approval for the specific contents contained therein.

Instead, the Agency requested, and the Commission affirmed the following through its Order approving the First Revised Plan:

- The Agency maintains flexibility to adjust its program requirements, and the documents and forms through which they are expressed, without further Commission approval as warranted;
- Any significant adjustments to those requirements should be preceded by a process to receive stakeholder feedback;
- The principle that Approved Vendors may be held accountable for the conduct of their agents, subcontractors, or designees under the Agency's marketing guidelines and other program requirements is a reasonable requirement consistent with a) the Commission's determination in Docket No. 17-0838 and b) the Agency's statutory authority to develop terms, conditions, and requirements applicable to the programs it implements.

6.13.1. Systems Energized Prior to Finalization of Consumer Protection Requirements

Additionally, as was also raised during the Docket No. 17-0838 proceeding, these consumer protection requirements are intended to apply to all Approved Vendors submitting projects into the Adjustable Block Program—but, as Section 1-75(c)(1)(K) of the Act envisions participation from "projects energized on or after June 1, 2017," some projects submitted into the Adjustable Block Program may have involved marketing, sales, disclosures, contracts, and other arrangements completed prior to the full development and finalization of the Initial Plan's consumer protection requirements.

By this time, the Agency assumes that all such systems have likely applied to the Adjustable Block Program. But it cannot be certain, and for such systems, the Commission's Order in Docket No. 17-0838 requires the following for consumer protection:

1. A signed contract amendment, that brings the contract or subscription agreement into full compliance with the minimum contract requirements from the Plan;
2. The disclosure form, signed by the customer post-contract execution; and
3. Proof that the brochure was provided to the customer.⁴⁴³

Failure to meet these requirements by the time the system is submitted to the IPA will result in rejection of the related system from the Adjustable Block Program.

Approved Vendors can attest via a declaration form in the application process if their customers are not responsive to good faith attempts to contact or for customers that refuse to sign an amended contract or disclosure form. The Agency has also included guidance in consumer protection documents for the customer allowing that customer to contact the program administrator or the IPA for additional information, to ask questions, or to submit concerns or complaints. The IPA and its Program Administrator retain the ability to exclude projects that in their determination represent deceptive marketing or bad faith business practices through complaints or other information brought to their attention (whether or not customers have signed contract amendments or disclosure forms), and will continue to “monitor, to the extent possible, potential Approved Vendors’ conduct to ensure good-faith attempts of compliance with the spirit of pending consumer protection requirements.”⁴⁴⁴

Consistent with the Commission’s Order, this streamlined compliance path applies only to those projects energized between June 1, 2017 and before the IPA’s consumer protections provisions were finalized on January 31, 2019.⁴⁴⁵

6.13.2. Community Solar

For community solar projects, the Approved Vendor must submit the Technical System Requirements information and, if not a copy of the contract between the project developer and the Approved Vendor (if they are separate entities), basic information concerning the underlying project (owner, size, location and interconnection date at a minimum, to be provided as part of the Adjustable Block application forms).⁴⁴⁶ The Agency reserves the right to request additional information about the project structure and financing in order to review project feasibility and contractual arrangements that could jeopardize consumer protections. Additional program terms and conditions related to subscribers of community renewable generation projects (both community solar and those that use other technologies) are discussed in Section 7.6.2.

Community solar projects are not required to demonstrate that they have acquired subscribers as part of their initial application. However, as described in Section 6.15.4, by the time that such systems are energized, minimum subscriber requirements must be met to be eligible for payment for RECs.

The Agency will use the subscriber mix to determine what adder, if any, will be given to the system, but the final adder (if any) used will depend on the subscription level demonstrated once the system is Energized pursuant to the terms of the REC Contract.

⁴⁴³ Docket No. 17-0838, Final Order dated April 3, 2018 at 108.

⁴⁴⁴ Docket No. 17-0838, Final Order dated April 3, 2018 at 107.

⁴⁴⁵ Docket No. 17-0838, Final Order dated April 3, 2018 at 107.

⁴⁴⁶ See id. at 107-108.

6.13.3. Monitoring of Consumer Complaints

The Program Administrator will provide consumer protection materials on a program website and through printed materials, and has developed its customer-facing [IllinoisShines.com](https://illinoisshines.com) website and program branding in part to accomplish this end. It plans to continue to modify and improve that the IllinoisShines.com site, and the Agency received useful feedback during various stakeholder comment processes as to what additional content could prove most helpful.

The Program Administrator provides a toll-free consumer protection telephone hotline and web-based complaint forms, and the Program Administrator will receive, respond to, and document complaints about marketing practices, sales practices, installations, and other aspects of solar marketing.

If warranted, the Program Administrator will refer complaints to the Agency and to appropriate state and federal agencies, including the Consumer Protection Division of the Illinois Attorney General's Office, or the Illinois Commerce Commission (e.g., for failure of installers to maintain their status as Certified Distributed Generation Installers). The Program Administrator maintains a public database of complaints (with any confidential or particularly sensitive information redacted from public entries), as well as a database of any disciplinary determinations issued (including the written notices and explanations of discipline) due to a violation of Program requirements. The Agency held a stakeholder comment process in September 2019 to refine what information on complaints should be published.⁴⁴⁷ Approved Vendors found by the Agency to have violated consumer protection standards or related Program requirements may be subject to suspension or revocation of their Approved Vendor status by the Agency (similarly, Designees may be suspended such that working with Approved Vendors on projects receiving state-administered incentive funding could subject Approved Vendors to discipline and result in the denial of project applications), and if in violation of local, state, or federal law, also potential civil or criminal penalties from other relevant authorities.

The Agency provides an annual written report to the Commission documenting the frequency and nature of complaints, and any enforcement actions taken. The first such report, covering calendar year 2019, was provided to the Commission through a filing in Docket No. 17-0838 on March 2, 2020. The second report covering calendar year 2020 was provided to the Commission through a filing in Docket No. 19-0995 on February 9, 2021.

6.13.4 Disciplinary Determinations

The Adjustable Block Program (and the Illinois Solar for All Program, for which the Plan's consumer protection requirements also apply) are ultimately state-administered incentive programs leveraging state- or utility-collected funds to provide additional incentives for photovoltaic project development. These programs do not constitute the solar project development market generally; an Approved Vendor, agent, or designee could simply choose to operate outside of the Agency's published marketing guidelines and consumer protection requirements should it choose not to avail itself of these additional incentive funding opportunities.

Consequently, the Agency views its disciplinary determinations as simply determining eligibility for state-administered incentives. No conduct is being restricted through the suspension or revocation

⁴⁴⁷ See <https://illinoisabp.com/consumer-complaint-database/> and <https://illinoisshines.com/consumer-complaint-database/>

of Approved Vendor or Designee status generally; all that is being restricted is the ability for an Approved Vendor to avail itself of additional incentive funding.

Nevertheless, the Agency appreciates that certain procedural safeguards should accompany its disciplinary determinations. Thus, through its First Revised Plan, the Agency proposed minimum procedural requirements applicable to such determinations. Specifically, mirroring and expanding on the process found in the Agency's Guidebook, the Agency proposed that Approved Vendors, Designees, agents, or other third parties potentially subject to Program discipline for a violation of the Agency's Marketing Guidelines or Consumer Protection requirements generally be afforded the following:

- A 45-day lead time will be provided to Approved Vendors and designees in order to prepare for and implement general changes to consumer protection requirements. Unless otherwise specified, the lead time granted will not prohibit Approved Vendors and designees from taking earlier steps towards compliance. In situations where the IPA determines that emergency adoption of a new or modified consumer protection is necessary, no lead time will apply; however, the Agency commits to enforce any such requirements with an eye toward the practical challenges inherent in immediate implementation.⁴⁴⁸
- In the event that the Program Administrator identifies that it believes an Approved Vendor, designee, or other party is not acting, or has not acted, in compliance with Program requirements in connection with the Program, the Program Administrator will notify the Approved Vendor through an e-mail that:
 - Outlines the problematic behavior;
 - Explains how the behavior is non-compliant with program requirements; and
 - Requests more information about the issue.
- No disciplinary determination (such as the suspension or revocation of the ability to participate as or on behalf of an Approved Vendor) will be made by the Agency's Program Administrator without the allegedly offending party having the opportunity to offer a written or oral explanation of the problematic behavior for review and analysis by the Program Administrator;
- All disciplinary determinations made by the Program Administrator will be communicated through a written explanation of the determination featuring at least the following:
 - A brief explanation of the infractions for which the Approved Vendor and/or Designee is being suspended;
 - A timeline of communications between the offending entity and the Program Administrator;
 - Specific reference to which specific Program requirement(s)/guideline(s) the offending entity violated;
 - An explanation of any suspension, including what specific conduct is no longer permitted in connection with the Program through the length of the suspension;
 - An explanation for how to appeal that disciplinary determination to the Agency and the deadline for submission applicable to any appeal.

⁴⁴⁸ See Docket No. 19-0995, Final Order dated February 18, 2020 at 56, 62. For an example of emergency adoption of a consumer protection, see ongoing COVID-19 updates here: <https://illinoisabp.com/covid-19-related-marketing-guidelines-and-updates/>

- The IPA will endeavor to address any appeals of disciplinary determinations within two weeks of receiving an appeal (although the need to receive additional documents or information may lengthen that timeline).
- Any appeal determination made by the IPA will include, at minimum, a clear statement of the Agency's decision, the consequences of that decision, and a supporting explanation as to why that decision was made.

This approach was affirmed by the Commission in the process of approving the First Revised Plan.⁴⁴⁹ Again, any party found in violation of the Program requirements is not barred from operating in the solar market in Illinois generally; it just may not participate in transactions benefitting from additional incentive payments provided through or by the Agency.

6.14. Application Process

The following section outlines the process and procedure that Approved Vendors will use to submit projects to the Program Administrator for review and approval, as well as how projects, once approved, will be placed into contracts with the utilities.

6.14.1. Batches

Under the Initial Plan Approved Vendors were required to submit projects bundled into batches. For the First Revised Plan, the Agency proposed (and the Commission approved) a simplification of the batch process. For a new Approved Vendor, there remains the requirement for a submittal of a first batch of at least 100 kW of projects, and that 75% of the capacity of that batch must be verified to be approved. Approved Vendors are allowed to select which batches approved systems are placed into, so that they can better manage their financing portfolios.⁴⁵⁰ Once systems' Part I applications are verified, and before they are sent to the Commission for approval, an Approved Vendor will be consulted and given the opportunity to specify how its verified systems are batched, so long as those batches of verified systems are at least 100 kW in size. **While the Agency believes an initial batch of 100 kW is not a significant barrier to new market entrants, the Agency welcomes stakeholder feedback on whether the initial batch size and/or 75% verification level for new minority or woman-owned Approved Vendors should be set at a lower level.**

For established Approved Vendors that have had a contract approved by the Commission and do not desire to assemble batches into portfolios in this way, projects may be submitted on a rolling basis, and as projects are verified, the Program Administrator will place them into new batches that will result in a contract and/or new confirmations with one utility.

Utilities may use one master agreement with multiple confirmations (one confirmation per batch) from an Approved Vendor, rather than having multiple contracts with the same vendor.⁴⁵¹ The systems within the batch/confirmation will be listed on a schedule (or product order) attached to the contract and may not be substituted once approved.

A batch may contain projects in different groups/blocks (and thus with different prices) and with different adders. The price for the RECs for each system will be based on the price available within the applicable block on the date of the submittal. The failure of any system to be developed (and thus

⁴⁴⁹ Docket No. 19-0995, Final Order dated February 18, 2020 at 57, 62.

⁴⁵⁰ See Docket No. 19-0995, Final Order dated February 18, 2020 at 75.

⁴⁵¹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 109.

the forfeiture of any collateral associated with that specific system) will not impact any of the other systems on the same schedule, although the Agency will monitor system failure rates across Approved Vendors. Approved Vendors with high failure rates may be required to provide additional information to the Agency for subsequent applications.

The Program Administrator will determine which utility will serve as the counterparty for each contract. While a batch may contain projects in multiple utility service territories, the Program Administrator will strive to assign contracts to the utility where the bulk of the projects are located, but may not always be able to do so because the Program Administrator will also consider how assigning contracts to each utility will allow each utility to meet its pro-rata share of the RPS REC targets and available RPS funding. The REC price for each system will be based on the applicable Group for that system's physical location, and not based on the identity of the counterparty utility to that contract.

After a batch of projects is created by the Procurement Administrator, the number of RECs to be delivered annually and payment amount(s) for the batch will be provided to the utility by the Program Administrator for purposes of contract/confirmation preparation (i.e., the utilities will track the RECs by batch rather than by individual unit). Utilities will send a report of RECs delivered by batch semi-annually to the Program Administrator.⁴⁵²

6.14.2. Systems below 25 kW

In responses to the Request for Comments that the Agency issued in June 2017, several commenters recommended that systems under 25 kW only be submitted once they are completed and energized, to minimize administrative burdens and avoid project attrition. While the Agency is sympathetic to those ideas, it did not adopt that recommendation for several reasons. It may be difficult, or impossible, to have appropriate consumer protections if the Agency sees information about a system only after it is completed. Preventing problematic behavior (such as deceptive information about system costs and payback times) should be done prior to the homeowner or business paying for the system; that would not be the case if systems apply only after being energized.

To be clear, the Program does not prohibit an Approved Vendor from submitting a "new" system that has already been energized, but the Approved Vendor will have to assume the risk that the system may not meet the required terms and conditions and could be rejected and thus not be included in a contract for the purchase of the system's RECs. A system that is rejected could be resubmitted at a later date if the deficiencies are cured, but the Agency cautions that some deficiencies may be difficult or impossible to cure (particularly when related to ensuring consumer protections from the beginning of the project's life).⁴⁵³

6.14.3. Application Fee

For each project, a non-refundable application fee must be paid to the Program Administrator or the Agency of \$10 per kW, not to exceed \$5,000 per project. This fee will be used to offset the administrative costs of running the program and will decrease the administrative fees that would otherwise be taken from the utility RPS budgets.

⁴⁵² See id.

⁴⁵³ See Section 6.13 above for further discussion of consumer protections applicable to systems energized after June 1, 2017 but before consumer protection requirements are finalized.

6.14.4. Project Review

The Program Administrator reviews project applications received by the Program and, as needed, requests additional information from the Approved Vendor in order to verify the submitted information and approve the project. An Approved Vendor will be given up to two weeks to cure deficiencies in an application. If deficiencies cannot be cured, the project application will be withdrawn. If the Approved Vendor can subsequently address the deficiencies, the Approved Vendor can resubmit the project (with a new application fee). For Approved Vendors participating in the proposed training/mentorship program described in Section 6.10, new application fees will be waived if the resubmittal happens within three months of the initial application being withdrawn.

For an initial 100 kW batch, if, after any attempts to cure deficiencies have been made, projects representing at least 75% of the capacity of the batch are reviewed and approved by the Program Administrator, that batch will be included in a contract presented to the Commission for approval. For established Approved Vendors, on a rolling basis in anticipation of the next scheduled Commission meeting, the Program Administrator will place verified projects for each Approved Vendor into batches for assignment to a counterparty utility, and prepare the confirmation information (and, in that case, master agreement information, if it is the Approved Vendor's first batch) or the contract information related to that batch.⁴⁵⁴

The Program Administrator will then submit the contract information for the batch to the Commission for approval. The Program Administrator will simultaneously forward the contract information to the applicable utility.⁴⁵⁵

An Approved Vendor that repeatedly submits deficient or noncompliant project applications may be subject to having its Approved Vendor status reviewed, and possibly suspended or terminated.

6.14.5. Converting System Size into REC Quantities

For each approved system, the Program Administrator will calculate a 15-year REC payment amount and obligation level, and that payment amount and delivery obligation will be included in the REC Contract. Approved Vendors will have the option of using a PVWatts calculated capacity factor (stated relative to a system's nameplate capacity in AC rating) automatically computed by the application platform, or proposing an alternative capacity factor based upon an analysis conducted using an equivalent tool. Alternative capacity factors may be proposed as part of each system's application and will be subject to review and approval by the Program Administrator. Systems using bifacial panels must submit an alternative capacity factor subject to review and approval by the Program Administrator. All capacity factors submitted must be for a system's first year; as stated in Section 6.16.1 below, annual REC delivery commitments will incorporate a 0.5% per year degradation factor.

6.14.6. Batch Contract Approval

The Commission meets approximately every two weeks. The Program Administrator will strive to efficiently process approved projects and assign them to batches for submittal to the Commission. The Agency understands that Commission practice is that items for consideration by the Commission must be submitted to be placed on its open meeting agenda at least 8 business days prior to each meeting.

⁴⁵⁴ See Docket No. 17-0838, Final Order dated April 3, 2018 at 115-116.

⁴⁵⁵ See id.

When the Program Administrator submits contract information to the Commission for approval, that submittal will include the Program Administrator's recommendation for approval of the batch, with a summary of factors relevant to Plan compliance. (Projects that are not approved by the Program Administrator are not submitted to the Commission.) This process is similar to that required for approval of contracts under annual electricity procurement plans pursuant to Section 16-111.5(f) of the PUA, or contracts under the Supplemental Photovoltaic Procurement Plan pursuant to Section 1-56(i)(5) of the Act.⁴⁵⁶

Pursuant to the Initial Plan, the Agency worked with Commission Staff to develop a Staff Report that includes the standards that the Commissions should use in considering the approval of contracts and product orders within the ABP and ILSFA.⁴⁵⁷ The Commission approved the recommendations contained in the Staff Report on December 19, 2018. Upon approval of this Second Revised Plan by the Commission, the Agency and Commission Staff will review and update that Staff Report if necessary.

Once a batch is approved by the Commission, the applicable utility will execute the REC contract and/or product order, as applicable. The Approved Vendor will then be required to sign the contract or product order within seven business days of receiving it from the utility.⁴⁵⁸ Failure to sign the contract or product order may subject the Approved Vendor to discipline under the Program. Additionally, when a contract or product order is not executed by the Approved Vendor within the seven business days after receipt, the constituent projects will be considered removed from the Program, with the option to re-apply later, subject to payment of a new application fee and available open block capacity (and subject to the applicant's Approved Vendor status not having been revoked due to the product order's non-execution). A collateral requirement to be held by the utility equal to 5% of the total contract value will be required in the form of either cash or a letter of credit with the utility within 30 business days of Commission approval of the contract.

In the First Revised Plan, the Agency recommended and the Commission approved a clarification to the collateral withholding process to be reflected in the updated REC contract (as discussed in Section 6.7). In cases where collateral was posted through a letter of credit, the Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last (or only, if a distributed generation system of 10 kW or smaller in size) REC payment in exchange for a release/reduction of the letter of credit.⁴⁵⁹

In the Initial Plan, the Agency provided an option to allow an Approved Vendor to be able to forgo posting collateral for a system that was already energized and instead have that collateral withheld from the REC payment. The intent of that provision was to allow systems that had been developed prior to the program launch to have a simplified process, recognizing of those systems' absence of development risk. However, the Agency has observed that this process has had an unintended

⁴⁵⁶ See id.

⁴⁵⁷ See: <https://www.icc.illinois.gov/downloads/public/edocket/490368.pdf>.

⁴⁵⁸ See id.

⁴⁵⁹ This provision would not apply to cash collateral for the following reason. If a project had a total REC value of \$100, \$5 of collateral would be due. To swap the 5% collateral for a withheld payment, \$100 in total payments (\$95 of REC payments plus a return of \$5 collateral) would need to be made, leaving a balance held by the utility of \$5, the same as before. On the other hand, if the collateral were a letter of credit, then a payment of \$95 would eliminate the need for the Approved Vendor to maintain the letter of credit (or portion thereof) for the remaining life of the contract.

consequence of encouraging some Approved Vendors to submit projects only after their energization as a way of avoiding any collateral obligation. If the project does not apply until after it is built, enforcing and ensuring consumer protections (and other program requirements) becomes more challenging. Ultimately, consumers are better served if their project can be reviewed and approved by the program (and then submitted to the ICC for approval) prior to being built. For this reason, the Agency will require upfront collateral in all cases, including for energized systems once the refreshed REC Contract containing applicable provisions is implemented.

Approved Vendors do not have the option to decline to post collateral within 30 business days once they have signed the contract. Failure to post collateral by the 30-business day deadline will violate the REC contract and may result in an Approved Vendor being suspended from further participation in the Program.

In stakeholder comment processes conducted by the Agency, parties have repeatedly requested allowing the rollover of collateral from projects withdrawn from the program to newly applied projects. The argument offered has been that, especially in the residential sector, the collateral requirement has created risks and costs for Approved Vendors who cannot control for decisions homeowners might make to cancel an installation. The Agency continues to believe that the collateral requirement is an important component of ensuring that only projects with a high degree of likely completion are submitted to the program. However, the Agency recognizes the concerns that have been raised repeatedly and is open to considering a narrow set of circumstances for allowing collateral from cancelled projects to be reallocated, such as if a homeowner sells the property prior to installation. The Agency welcomes stakeholder comments on what might be an acceptable list of such circumstances, and on the mechanics of how those exceptions could be applied (such as what level of proof would be appropriate).

6.15. Project Development Timeline and Extensions

6.15.1. Development Time Allowed

Once a contract for a batch has been executed by the Approved Vendor and the utility, the next step is for projects not yet developed to be developed and energized. The following timelines are based upon the REC delivery contract execution date, such that any delays in processing and approving an application will not reduce the time available for development.

- Distributed generation projects will be given one year to be developed and energized.
- Community solar projects will be given 18 months to be developed, energized, and demonstrate that they have sufficient subscribers.

A project that is not completed in the time allowed (plus any extensions granted) will be removed from the contract, and the REC volume associated with the project will be eliminated from the contract. The Approved Vendor will also forfeit the posted collateral associated with the project. Any forfeiture of collateral by the Approved Vendor under the REC contract will be considered to be returned to the utility's available Renewable Resources Budget and will become available for REC delivery contracts for other projects.

A project that is not completed in time and is removed from the contract may be subsequently re-submitted by an Approved Vendor, but will be treated like any other new system being submitted.

Since the development of the January 2019 REC delivery contract and the subsequent execution of that contract in connection with projects, one circumstance not adequately addressed through that contract deserved Commission attention. In some instances, the developer of an Adjustable Block Program project may learn that development of the project is no longer feasible—whether due to financing falling through, the system host no longer wanting to move forward with the project, or myriad other circumstances. Under the language of the original REC delivery contract, such a system could not be removed from the contract until contract requirements related to a Seller meeting the system’s energization deadline were not timely met, a contract violation which may not occur until over one year from the point at time in which the Seller learns that development is no longer feasible.

Thus, in the First Revised Plan, the Agency sought Commission permission to allow the Seller to provide notification to the Buyer, the Agency, and the Commission that it is exercising its option allowing for a system’s removal from the contract because the Approved Vendor no longer wished to develop that system. Under these circumstances, the Seller would forfeit the posted Performance Assurance applicable to the system. Doing so allows the contract parties (the utility Buyer and Approved Vendor Seller) to no longer maintain a contractual obligation when performance is no longer intended, while also providing clarity to the Agency and its Program Administrator about the availability of new Program capacity through removal of a project from a REC contract. This proposal was approved by the Commission in Docket No. 19-0995, and the Agency has since developed specific forms and procedures to effectuate this option for Sellers.⁴⁶⁰

6.15.2. Extensions

Extensions to the energization deadline will be granted for the following circumstances.

- An indefinite extension will be granted if a system is electrically complete (ready to start generation) but the utility has not approved the interconnection. The Approved Vendor must document that the interconnection approval request was made to the utility within 30 days of the system being electrically complete, yet not processed and approved.
- A 6-month extension will be granted for documented legal delays, including permitting delays.
- A 6-month extension will be granted upon payment of a refundable \$25/kW extension fee, for distributed generation systems, and up to two 6 month extensions for community solar projects (the second extension is only for achieving the required subscriber rate, not for project completion and energization, and will require an additional refundable \$25/kW fee). The extension fee(s) is payable to the contracting utility and would be refunded as part of the first (or only for systems up to 10 kW) REC payment.
- The Agency may also, but is not required to, approve additional extensions for demonstration of good cause.⁴⁶¹

⁴⁶⁰ See Docket No. 19-0995, Final Order dated February 18, 2020 at 80.

⁴⁶¹ Good cause extensions have been the primary means of allowing for extensions in energization deadlines due to COVID-19 related delays, as described extensively in Chapter 3.

6.15.3. Project Completion and Energization

The Approved Vendor will provide the Program Administrator with a status update on each project under development but not yet energized at least every six months and will inform the Agency of any significant changes to the system.⁴⁶² For community solar projects, the update will include an update on the status of acquiring subscribers. The Agency and Program Administrator have developed a standardized form (including standard status categories to simplify reporting) for this purpose.

Once a project is energized, the following information is required from the Approved Vendor for the Program Administrator to approve the final project as Energized for purposes of the REC delivery contract and authorize commencement of payment for RECs:

- Final system size
- Final system specific capacity factor and 15-year REC production estimate
- GATS or M-RETS unit ID⁴⁶³
- Certificate of Completion of Interconnection or comparable documentation^{464, 465}
- Photographic documentation of the installation
- Disclosure of any changes to the system technical specifications that occurred between the initial application and the completion of the project
- Identity of the installer (must be a Qualified Person under Part 468 of the ICC's Rules)

Additional requirements may be published (such as through the Program Guidebook) by the Program Administrator if the Agency determines that such requirements are warranted, and the Program Administrator may reference other sources (such as public databases) to determine the accuracy of any submissions.

If the final system size is larger than the proposed system size such that it would cause the system to change from the up to 10 kW to the over-10 kW category, the payment terms will be adjusted from the full payment on energization to 20% on energization and the balance over the next four years. The price per REC will also be changed to the applicable REC price for the over 10 kW category in effect at the time when the system is energized.

For systems over 10 kW, the final REC Price will be based on the final system size if that final system size would cause the REC Price to remain the same or to decrease. A system that is developed at a size smaller than the original application will not be eligible for a higher REC Price.

The quantity of RECs used for payment calculations is based on the lesser of the RECs calculated based on the proposed (Part I) system size and capacity factor, and the RECs calculated based on the final (Part II) system size and capacity factor. The final capacity factor can be adjusted down from the initial capacity factor but cannot be increased from the original capacity factor, including changes in capacity factor due to switches between tracking technology, non-tracking and tracking systems, and bifacial vs standard module use. In this way, a system that is built smaller than planned will not benefit from excess REC payments that could result from purposefully submitting the project at a

⁴⁶² For systems under 25 kW, that status update is only be required for a system where there is a change in status (e.g., a project being completed, or canceled).

⁴⁶³ GATS or M-RETS registration must be complete and unit ID verifiable through GATS or M-RETS public reports.

⁴⁶⁴ Comparable documentation would only apply for a rural electric cooperative or municipal utility that does not provide a Certificate of Completion of Interconnection.

⁴⁶⁵ Per Section 1-75(c)(1)(K) of the IPA Act, the date of final interconnection approval must be no earlier than June 1, 2017.

larger size than really intended. On the opposite side, if a project's final system size is significantly larger than the planned system size, an increase in the payment due could present unexpected budget management challenges. An Approved Vendor has the option of canceling and resubmitting a system if the final size is larger than the proposed system to align the REC quantities or if it desires to have the system change from a distributed generation project to a community solar project, or vice versa. However, the applicable REC price upon resubmittal is the price of the block open at that time (and subject to any applicable waitlists), and not at the time of the original submittal. Because the Program Administrator will need to review the system design (because of the change in system size), a new application fee will be required. If a project is resubmitted, the collateral associated with the original system may be applied to the resubmitted system, if approved.

The Agency emphasizes that, while the Approved Vendor is the entity that receives REC payments, the terms of sharing that REC payment value with customers (completely, partially, or not at all; immediately or over time; directly or indirectly) or obligations associated with a system's performance assurance payment are left to a customer and Approved Vendor (or customer and designee) to work out between themselves prior to executing an agreement.

The Agency reserves the right to request more information on an installation, and/or conduct on-site inspections/audits of projects to verify the quality of the installation and conformance with the project information submitted to the Agency. Projects found not to conform with applicable installation standards and requirements, or projects found not to be consistent with information provided to the Agency will be subject to removal from the program if the deficiencies cannot be remedied. Likewise, Approved Vendors who repeatedly submit projects featuring application errors or inconsistencies with Program requirements may be subject to suspension or termination of their Approved Vendor status.

6.15.4. Additional Requirements for Community Solar Projects

A community solar project must demonstrate that it has met a minimum subscription level to be considered energized and eligible to receive payment for RECs. At least 50% of the capacity of the project must be subscribed at the time of energization in order to receive payment for RECs, and that payment will be based upon calculating the number of RECs that correspond with the amount of the project's capacity that has been initially subscribed. The Approved Vendor shall report subscription levels on a quarterly basis during the first year. The calculation of the number of RECs for payment will be updated after one year of operation (based on the final quarterly report of that first year) to allow for the acquisition of additional subscribers. A community solar project may request one additional extension (with a refundable extension payment as provided for in Section 6.15.2) to its energized date if it needs additional time to acquire subscribers.

To the extent that an Approved Vendor demonstrates additional subscriptions or updated subscription mixes that would entitle the Approved Vendor to a greater payment, the contract will require that subsequent payments reflect the increased value for quarters where the additional subscriptions or updated subscription mix entitle the Approved Vendor to additional revenue. If subscriber levels (or mixes) change in such a manner that contract value is reduced, the additional payments would also be adjusted downwards accordingly.⁴⁶⁶

⁴⁶⁶ See Docket No. 17-0838, Final Order dated April 3, 2018 at 118.

The calculation of the maximum number of RECs due payment is determined by the project's subscription level after one year of operation (and will be subject to the maintenance of subscription levels as described in Section 6.17). For example, if a project is expected to produce 1,000 RECs/year and after one year of operation is 95% subscribed (on a project capacity basis), then the annual REC production value used for the contract payment level would be 950 RECs. Under the REC delivery contract, the Approved Vendor would then be obligated to deliver to the utility 95% of the RECs produced by that system each year. The ownership (and any subsequent transfer or sale) of the remaining 5% of RECs would be outside of the contract.

The adders for small subscriber participation (i.e., for a minimum of 25%, 50%, or 75% of energy being subscribed) will only be added (on a prorated basis) to the REC price if the project demonstrates that level of participation for the subscribed amount at the time of energization. If the subscription level has not been met by the time of energization, the adder will be held back from the initial payment and the system will have to wait until it has been in operation for one quarter to demonstrate that it has begun to meet the small subscriber participation level to begin to receive this adder. If the small subscriber subscription rate is met, then the full value of the adder will be added pro-rata to the remaining payments.

Ongoing requirements for overall subscription levels and small subscriber participation are discussed further in Section 6.16.

6.15.5. REC Delivery

Once a system is energized, it is required to begin REC delivery. For systems larger than 5 kW, the first REC must be delivered within 90 days of when the system is energized and registered in GATS or M-RETS. For systems smaller than 5 kW, 180 days will be allowed. The 15-year delivery term will begin in the month following the first REC delivery and will last 180 months.

Approved Vendors will be required to set up an irrevocable Standing Order for the transfer of RECs from the system to the utility.⁴⁶⁷ As the Agency understands that automatic transfers can only be terminated with the consent of both parties, this will reduce the risk to the utility that the RECs could be sold to another party after the utility has paid for them.

As part of the Annual Report discussed in Section 6.17, the Approved Vendor will report on any systems that have not delivered a first REC, and report on any systems that have not delivered RECs for more than a year from their previous delivery. The report will also detail what corrective actions will be taken to ensure future deliveries. In the event of failure to remedy non-delivery of RECs, the utility may draw on the collateral it holds from the Approved Vendor.

6.16. Ongoing Performance Requirements

A significant challenge for the Adjustable Block Program is that the payment for RECs is front loaded; all RECs are paid for on energization for systems up to 10 kW, and all payments for systems over 10 kW will be made within the first four years of energization. Yet the contracts for REC delivery have a 15-year obligation for the RECs to be delivered. This creates a situation in which, absent any additional measures, the buyer (the utility) will be unable to use the typical contractual tool of withholding payments for the item not yet received to ensure REC delivery. Fortunately, the Act

⁴⁶⁷ See Section 10.2 of the GATS Operating Rules available at <https://www.pjm-eis.com/~media/pjm-eis/documents/gats-operating-rules.ashx>.

anticipated this issue and requires that “[e]ach contract shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract.”⁴⁶⁸

The Agency will utilize the approach described below to ensure REC delivery over the full term of the contracts. This approach will also ensure proper matching of adders for photovoltaic community renewable generation projects at different levels of residential subscription levels.

REC delivery obligations will be managed at a portfolio level. As projects are completed and become energized, each Approved Vendor will therefore have a portfolio of systems with REC delivery obligations from the various contracts that it has with each utility. The obligation to ensure REC delivery is at the contract level rather than the individual project level. In this way, the natural variation that some systems will produce more RECs than forecast and others fewer RECs reduces the risk of contract default, as compared to project-level contracts, and allows for ease in contract administration.

6.16.1. Credit Requirements

An Approved Vendor is required to post collateral equivalent to 5% of the total contract value within 30 business days of when each Batch’s contract (or product order) is approved. As described in Section 6.14.6, if the collateral was provided in the form of a Letter of Credit, then the Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last REC payment for the system (or only REC payment for small systems) in exchange for not needing to maintain the collateral in the form of the Letter of Credit. In this situation, the collateral would be reduced as described below, and fully returned at the end of the contract (net any amounts that were drawn to meet contractual obligations). As systems are energized, this collateral amount (or deferred payment) will be maintained through the life of the contract. This requirement will be maintained at the portfolio level, not the individual contract or system level. The collateral amount is based upon the contract value at the time of ICC approval of the product order and is not adjusted if the final system size and/or capacity factor (and thus resulting quantity of RECs for payment) is lower than the initial approved amount.

By maintaining collateral requirements at the portfolio level, Approved Vendors can better manage the risk that some systems may underperform (or have other problems) while others may overperform. This allows the collateral level to be lower than it would be if maintained at the system level.

The Agency wishes to emphasize that this Plan does not prescribe the source of funds for collateral, whether it be an Approved Vendor’s cash on hand, bank borrowings, the project owner’s funds, customer-provided funds, a letter of credit, or some other source.

Nonetheless, an Approved Vendor will be responsible for delivering RECs each year under its contracts (subject to the reduction options described in the following Section). On an annual basis, failure to deliver RECs for the previous year will result in the utility drawing on the collateral to be compensated for the undelivered RECs from that year for which payment was already received. After any such drawing, the Approved Vendor will need to restore its collateral level to bring it back up to the 5% of remaining value of the portfolio within 90 days. If the amount of collateral held for an Approved Vendor is insufficient to compensate the utility, the Approved Vendor will be required to

⁴⁶⁸ 20 ILCS 3855/1-75(c)(1)(L)(iv).

pay the utility for the balance of the value of the undelivered RECs from that previous year. Failure to make payment and/or maintain the collateral requirement may result in the Approved Vendor's suspension from participating in the Program.

Additionally, the Agency understands and appreciates that the natural degradation of photovoltaic system's productive capacity will likely result in reduced delivery quantities in the later years of a system's performance under a REC delivery contract. Annual contractual REC delivery volumes will thus be decline by 0.5% each year, which the Agency believes should help ensure that collateral is not unfairly drawn upon due to reduced system performance.⁴⁶⁹

Reconciliation of REC deliveries and collateral requirements will be conducted on an annual basis based on the Annual Reports filed by the Approved Vendors as described in Section 6.17.

6.16.2. Options to Reduce REC Delivery Obligations

Section 1-75(c)(1)(L) of the IPA Act provides that "[t]he electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation."⁴⁷⁰ The capacity factor as described in Section 6.14.5 will be used to calculate the number of expected RECs each system generates, and thus the overall payment for that system. If a system produces more RECs than expected from that calculation, then no adjustment would be made to payments or to the statutorily mandated 15-year REC delivery term. However, if the system produces fewer than the contracted quantity of RECs, then the following conditions apply.

The Agency expects each Approved Vendor to take the steps necessary to ensure that projects contained within its portfolio meet all expected REC deliveries. This may include working with system owners to ensure that ongoing maintenance and repairs of systems occurs as well as to ensure that meter/inverter data is properly transferred to GATS or M-RETS for the creation of RECs. Furthermore, Approved Vendors will be responsible for ensuring the ongoing transfer of RECs to the applicable utility. However, because weather and other factors may impact annual production values, REC delivery performance will be evaluated on a three-year rolling-average basis, although any overproduction may be carried forward (or "banked") for performance evaluation and collateral purposes into future contract years without expiration.⁴⁷¹ However, a project or portfolio is not entitled to additional compensation if a carryforward remains as project-specific contracts expire.⁴⁷²

There are circumstances where a system may not be able to deliver the RECs it was expected to produce; the Agency believes that reasonable accommodations should be made for these situations that appropriately balance the requirements for the utilities to comply with RPS targets and their expectation to receive RECs for which payment has already been made while acknowledging that unexpected situations may arise at no fault of the Approved Vendor.

In force majeure circumstances (including, but not limited to, physical damage to the system from fires, tornados, etc.) the Approved Vendor may request to have a delivery obligation suspended, reduced, or eliminated without penalty.⁴⁷³ Approval of the recognition of a force majeure event

⁴⁶⁹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

⁴⁷⁰ 20 ILCS 3855/1-75(c)(1)(L)(ii).

⁴⁷¹ All RECs must be delivered to the counterparty in the delivery year when produced, regardless of any overproduction under the contract. See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

⁴⁷² See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

⁴⁷³ Specific circumstances that constitute force majeure have been outlined and memorialized in the REC Contract.

requires consensus between the Agency and the contracting utility. Curtailments by either the utility (including those through a smart inverter) or the RTO that result in reduced REC production would allow for reduced REC delivery obligations.

In the case of reductions or eliminations of delivery obligations, the Approved Vendor must demonstrate what measures have been taken that do not adequately cure the situation (such as filing and receiving an insurance claim that is inadequate to restore the system to operation). For the suspension of delivery obligations, the Approved Vendor must demonstrate that reasonable measures are being taken to have a timely restoration of production. Approved suspension of delivery obligations will serve to change the end date for the 15-year REC delivery timeline to reflect the time the delivery obligations were suspended.

An Approved Vendor may also determine that a system is not performing at the level expected in the absence of force majeure circumstances. In this circumstance, the Approved Vendor may request to have the delivery obligation related to that system within its portfolio reduced in exchange for the return to the utility of a payment adjustment to account for all undelivered RECs at the original delivery level as of the time of the request.

6.17. Annual Report

On an annual basis, each Approved Vendor is required submit an Annual Report of the contracts and systems in its portfolio.⁴⁷⁴ The Annual Report serves as the basis for verifying that RECs from projects are being delivered to the applicable utility, and, absent corrective actions taken by the Approved Vendor, will be used to determine what actions should be taken by the utilities to enforce the contractual requirements that RECs are delivered, including, but not limited to, drawing on collateral. Additionally, the Annual Report will be used by the Agency to consider the ongoing eligibility of an Approved Vendor to continue participation in the program.

For distributed generation systems, the report will include information on:

- RECs delivered by each of the systems in the portfolio
- Status of all systems that have been approved, but not yet energized, including any extensions requested and granted
- Energized systems that have not delivered RECs in the year
- Balance of collateral held by each utility
- A summary of requests for REC obligations reductions due to force majeure events
- A summary of requests for REC obligations, suspensions, reductions, or eliminations due to force majeure events
- Information on consumer complaints received
- Other information related to ongoing program participation, including use of graduates of job training programs and other information related to increasing the diversity of the solar workforce⁴⁷⁵

⁴⁷⁴ Approved Vendors may request confidential treatment of the Annual Report. However, aggregated information from Annual Reports may be publicly disclosed by the Agency to the extent that it does not disclose Approved Vendor-specific confidential information.

⁴⁷⁵ As discussed in the Commission's Order approving the First Revised Plan, this requirement was added in order to learn from and celebrate how the increase in solar development in Illinois is improving diversity in the state's renewable energy workforce. The IPA commits to gathering this information for informational purposes only. See Docket No. 19-0995, Final Order dated February 18, 2020 at 87.

For community solar projects, the report will also include:

- Percentage of each system subscribed on a capacity basis
- The number and type of subscribers (e.g., residential, small commercial, large commercial/industrial), including capacity allocated to each type
- Subscriber turn-over rates

The Agency will review the annual reports to assess compliance with the requirements of the Adjustable Block Program and, if there are shortfalls of REC deliveries or subscription levels for photovoltaic community renewable generation projects, will coordinate with the applicable utility on what remedies should be taken, including drawing on collateral.⁴⁷⁶ For this process and those described in the next two paragraphs, the performance evaluation and collateral draw methodologies have been specified in the standard REC delivery contract.

For community solar projects, subscription levels must be maintained to remain eligible for REC payments. If the annual report shows that subscriber levels on a rolling average basis have fallen below the subscribership level that the project contractually committed to, then if REC payments are still due, those payments will be reduced as described earlier in this chapter; if all payments have been made, then the Agency will work with the applicable utility on what remedies should be taken including drawing on collateral. If a project's subscribership falls below 50% for a given delivery year, no payment would be owed to the project for that delivery year, and a payment reduction or collateral draw would result (although the project could regain 50% subscribership the following year and qualify for payment in relation to that year).

A similar review will be conducted for projects that have received a small subscriber participation adder but do not maintain sufficient levels of small subscriber participation. If small subscriber participation levels are not maintained and there are remaining REC payments due, those payments will be reduced (to either the actual small subscriber adder category that has been maintained, or to remove the adder altogether if the level falls below 25%). If all payments have been made, then the Agency will work with the applicable utility on what remedies should be taken including drawing on collateral.

Approved Vendors will be given 90 days to cure any deficiencies found by the Agency and/or utilities, and the failure to submit annual reports or cure deficiencies may carry consequences under REC delivery contracts and/or result in disciplinary action under the Program.

⁴⁷⁶ The Agency will request on a semi-annual basis a report from each utility on RECs delivered by contract.

7. Community Renewable Generation Projects

Community Renewable Generation remains a developing concept in Illinois. It is intended to allow consumers to participate in renewable energy generation even if they are unable to have an on-site system at their home or business, and to offer a more direct connection to the benefits of renewable energy than signing up for a renewable energy retail supply offer from an Alternative Retail Electric Supplier (where information about the specific sources, costs, and benefits of the renewable energy and the underlying generating system(s) may not be readily available).

Community, or “shared,” renewable energy is growing nationally, most often in conjunction with solar power. The Solar Energy Industries Association reports that nearly 3,100 MW of community solar had been developed through 2020.⁴⁷⁷

Many policy issues that have been debated in other states are resolved in Illinois through the Act itself, including elements of project size, ownership structures, and the minimum number and type of subscribers. In addition to explaining those aspects of Illinois law, in this Chapter, the Agency outlines the terms and conditions for the Community Renewable Generation Program that are not prescribed by the Act.

7.1. Statutory Overview

The Act contains several key provisions designed to make community renewable generation economically viable and practical in Illinois. These provisions create a program, provide it with important structure, and increase the benefits to participants through changes to net metering and bill crediting and the ability to monetize the value of RECs from the systems.

Section 1-10 contains several key definitions:

"Community renewable generation project" means an electric generating facility that:

(1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;

(2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act;

(3) credits the value of electricity generated by the facility to the subscribers of the facility; and

(4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.

[...]

"Subscriber" means a person who (i) takes delivery service from an electric utility, and (ii) has a subscription of no less than 200 watts to a community renewable generation project that is located in the electric utility's service area. No subscriber's subscriptions

⁴⁷⁷ <https://www.seia.org/initiatives/community-solar>.

may total more than 40% of the nameplate capacity of an individual community renewable generation project. Entities that are affiliated by virtue of a common parent shall not represent multiple subscriptions that total more than 40% of the nameplate capacity of an individual community renewable generation project.

[...]

"Subscription" means an interest in a community renewable generation project expressed in kilowatts, which is sized primarily to offset part or all of the subscriber's electricity usage.

These three definitions create the core of the idea of community renewable generation, where subscribers pay for shares or some other "interest" in a centralized (but small) renewable power project, receiving bill credits in exchange. It can be seen as a way of giving customers choices about their electricity generation in a manner that can serve as an alternative to the options created by the establishment of retail choice through the Electric Service Customer Choice and Rate Relief Law of 1997.⁴⁷⁸

Section 1-75(c)(1)(N) creates the community renewable generation program:

(N) The long-term renewable resources procurement plan required by this subsection (c) shall include a community renewable generation program. The Agency shall establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties. Any plan approved by the Commission shall allow subscriptions to community renewable generation projects to be portable and transferable. For purposes of this subparagraph (N), "portable" means that subscriptions may be retained by the subscriber even if the subscriber relocates or changes its address within the same utility service territory; and "transferable" means that a subscriber may assign or sell subscriptions to another person within the same utility service territory.

Electric utilities shall provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber as specified in Section 16-107.5 of the Public Utilities Act.

The Agency shall purchase renewable energy credits from subscribed shares of photovoltaic community renewable generation projects through the Adjustable Block program described in subparagraph (K) of this paragraph (1) or through the Illinois Solar for All Program described in Section 1-56 of this Act. The electric utility shall purchase any unsubscribed energy from community renewable generation projects that are Qualifying Facilities ("QF") under the electric utility's tariff for purchasing the

⁴⁷⁸ One aspect of the success of retail competition in Illinois has been municipal aggregation programs whereby a municipality negotiates an electric supply offer from an ARES on an opt-out basis for eligible retail customers. The Agency understands that those customers who participate in a municipal aggregation program remain individual customers and thus would be considered individually for the purposes of the 40% cap on individual subscriptions. The aggregator would not be considered a subscriber to a community renewable generation project.

output from QFs under Public Utilities Regulatory Policies Act of 1978. The owners of and any subscribers to a community renewable generation project shall not be considered public utilities or alternative retail electricity suppliers under the Public Utilities Act solely as a result of their interest in or subscription to a community renewable generation project and shall not be required to become an alternative retail electric supplier by participating in a community renewable generation project with a public utility.

This Chapter describes the “terms, conditions, and program requirements” applicable to projects participating in an IPA program featuring community renewable generation project participation and how RECs produced by that facility are purchased. Certain other aspects of the Program requirements are administered by the applicable utility, and the Agency will coordinate with those entities to ensure compliance with the Act.

While the Act defines community renewable energy as including solar, wind, biomass, and other renewable sources, it creates an Adjustable Block Program only for photovoltaic generation, directing the Agency to “purchase renewable energy credits from subscribed shares” of community solar projects.⁴⁷⁹ By procuring those projects’ RECs, the Agency is able to offer an additional financial incentive or cost offset for customers choosing community solar.

Subscribers capture the value of their community energy subscription in the form of a “monetary credit” applied to the subscriber’s subsequent utility bill for service, in proportion to the net output of their subscription to the project. The determination of that subscriber utility bill credit is not the subject of this Plan, and is instead established through tariffs filed by the utilities with the Illinois Commerce Commission as discussed further below. Instead, the Agency’s role is simply in the procurement of RECs—which helps support the development of new projects and should reduce the subscriber’s subscription price. While subscribers may not (if their subscription does not take the form of equity in the project) necessarily directly receive revenue for the RECs procured for the utilities by the Agency, that revenue should factor into the economics faced by the project developer and impact the subscription offer made to subscribers.

The monetary credits for net energy production flow from provisions of the Public Utilities Act that expand the concept of net metering, which had previously been available for distributed generation, to become available for community renewable generation subscribers. The previous version of Section 16-107.5(l) of the Public Utilities Act before the enactment of Public Act 99-0906 provided that electric utilities merely “shall consider” whether to allow community-owned facilities or meter aggregation projects in a single building. The revised version of that Section adds the requirement to Section 16-107.5 that utilities *shall allow*⁴⁸⁰ net metering for subscribers to “community renewable generation projects,” as well as the other two types of community renewable projects.

The law requires an “electricity provider” (meaning an electric utility or alternative retail electric supplier) to provide net metering credits for a community solar subscriber’s share of a project’s net electricity production at the subscriber’s energy supply rate.⁴⁸¹

⁴⁷⁹ As discussed elsewhere, the Agency understands “purchase” effectively to mean “procure” as used in this provision, as the Agency would not directly enter into contracts with renewable providers using non-RERF (or otherwise non-state-held) funds.

⁴⁸⁰ 220 ILCS 5/16-107.5(l)(1).

⁴⁸¹ Community solar projects are to receive energy-only net metering credits starting from the enactment of Public Act 99-0906 on June 1, 2017 (or whenever each electricity provider implements the tariff or terms to do so following June 1, 2017), in contrast to other types of

Public Act 99-0906 also required that each electric utility file a community solar net metering tariff within 90 days after the new law's effective date of June 1, 2017. Each of ComEd, Ameren Illinois, and MidAmerican filed a proposed tariff during August of 2017, and the Commission approved all three tariffs on September 27, 2017.⁴⁸² These tariffs are discussed further in Section 7.7 of this Plan.

ComEd's tariff consisted of modifications to its Rider POGCS (Parallel Operation of Retail Customer Generating Facilities Community Supply), Rider POG (Parallel Operation of Retail Customer Generating Facilities), Rider PORCB (Purchase of Receivables with Consolidated Billing), and Rate RESS (Retail Electric Supply Service). Ameren's tariff consisted of a complete revision to its Rider NM (Net Metering) to now incorporate provisions governing community renewable net metering. MidAmerican's tariff created a new Rate NMS to embody its new community renewable net metering program.

7.2. Eligible Generating Technologies and Procurement/Program Eligibility

Only photovoltaic community renewable generation projects are eligible to participate in the Adjustable Block Program outlined in Chapter 6. Other types of community renewable generation projects (the listing for which can be found in the definition of "renewable energy resources" found in Section 1-10 of the IPA Act) were eligible to participate in the competitive procurement outlined in Chapter 5 of the Initial Plan. These two procurement options define the process by which a system would come under contract with a utility to sell its RECs, and each option features different payment terms. For example, the Adjustable Block Program has front-loaded REC payments, while competitive procurements feature payment for RECs as they are delivered. Other than these contractual differences, the Agency believes all community renewable generation projects (including those participating in the Adjustable Block Program) should be treated the same as to other terms and conditions that follow in this Chapter, unless specifically noted.

For non-photovoltaic community renewable generation projects, the price per REC based upon the price of each winning bidder's bid in the competitive procurement and is not tied to any adders or requirements for residential subscription levels.

For this Second Revised Plan, given the status of the RPS budget and the challenges observed in the prior non-photovoltaic community renewable generation project procurement, the Agency is not proposing an additional non-photovoltaic community renewable generation project procurement.

7.3. Co-location of Projects

Co-location of projects occurs when multiple projects are located adjacent to each other, perhaps using the same point of interconnection. Co-located projects can be structured to maximize income from incentives, such as by dividing up a larger project into smaller pieces that qualify for higher incentives. Community Renewable Generation Projects are defined in the Act as being smaller than or equal to 2,000 kW, and for photovoltaic projects, the Adjustable Block Program includes adders for smaller projects. Co-location strategies could therefore result in the gaming of incentives.

Minnesota offers two points of experience with the issue of co-location, for both community wind and community solar. Under both policies, larger projects were structured as a series of smaller

distributed generation, which will continue to receive full retail rate net metering from June 1, 2017 until total net metering for that electricity provider reaches 5% of the electricity provider's peak demand, as discussed in Chapter 6.

⁴⁸² See ICC Docket Nos. 17-0350 (ComEd), 17-0368 (MidAmerican), and ICC tariff No. ERM 17-144 (Ameren Illinois).

projects to qualify for higher incentives, undermining the legislative intent of promoting distributed, community-owned projects. A 30 MW wind project, owned by 15 corporate entities with the same owners, was developed under the Minnesota Community-Based Energy Development (C-BED) tariff program, which was intended to encourage community-owned wind projects of 2 MW or less. That program was reformed in 2003 to be more prescriptive, limiting ownership to Minnesota residents, with a single owner limited to a 15% share of a project.⁴⁸³

The more recent Minnesota Community Solar Gardens policy led to a similar problem. While the legislature capped project size at 1 MW, it did not address co-location issues. As a result, 15 co-located, aggregated projects were proposed between 10 and 20 MW, three between 20 and 30 MW, and two in the 30 to 50 MW range. One developer, Sunrise Energy Ventures, filed applications for 100 projects within the first hour of the program. When the state Public Utilities Commission (“PUC”) imposed co-location caps of 5 MW for projects with filed applications and 1 MW for newly proposed projects, Sunrise appealed to the Minnesota Court of Appeals. The Court, however, affirmed the PUC’s decision to implement caps.⁴⁸⁴

While co-location can undermine the concept of smaller and more geographically diffuse projects, it can also capture economies of scale from larger projects: large, available parcels with good interconnection points can be low-cost and efficient ways to develop large amounts of renewables quickly. Low development costs could help compensate for the higher marketing and customer acquisition costs of community renewable generation and provide greater benefits to low-income customers. Also, different owners might apply to develop completely distinct projects at different times, that just happen to be on adjacent parcels; restrictive rules would limit the development of especially attractive parcels of land.

7.3.1. Co-location Standard

In enacting Public Act 99-0906, the General Assembly expressly included a size limit for community renewable generation projects of 2,000 kW,⁴⁸⁵ and the Agency does not believe it should ignore the intent of that size limit being included in the definition of community renewable generation projects. Additionally, as discussed in Section 6.5.1, the Agency seeks to avoid the situation in which multiple smaller projects are co-located in order to obtain the higher REC prices available to smaller systems.

To appropriately balance these competing issues, in recognition of a need to avoid problems of the types seen in Minnesota,⁴⁸⁶ and generally consistent with the Commission’s Order approving the

⁴⁸³ Jessica A. Shoemaker and Christy Anderson Brekken, Farmers’ Legal Action Group, *Community Wind: A Review of Select State and Federal Policy Incentives*, August 2006, <http://www.flaginc.org/wp-content/uploads/2013/03/CommWindAug061.pdf>.

⁴⁸⁴ Mitchell Williams, Selig Gates & Woodyard PLLC, “Community Solar Gardens: Minnesota Appellate Court Allows Public Utility Commission to Implement Caps on Usage,” Lexology, August 23, 2016. <http://www.lexology.com/library/detail.aspx?g=c4690835-61c4-40cf-8105-0cc8d3229c77>.

⁴⁸⁵ See 20 ILCS 3855/1-10 (“Community renewable generation project’ means an electric generating facility that . . . is limited in nameplate capacity to less than or equal to 2,000 kilowatts.”).

⁴⁸⁶ These principles are derived from the definition adopted in Minnesota regarding co-location. See, Minnesota PUC, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program. Order Adopting Partial Settlement As Modified. August 6, 2015. Docket No. E-002/M-13-867. <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={43AC9E59-AD57-44FE-A57A-5F8A572D3C74}&documentTitle=20158-113077-01>.

Initial Plan in Docket No. 17-0838,⁴⁸⁷ the following policy is applicable to the co-location of Community Solar projects participating in the Adjustable Block Program:

- No Approved Vendor may apply to the Adjustable Block Program for more than 4 MW of Community Solar projects on the same or contiguous parcels (with each “parcel” of land defined by the County the parcel is located in).⁴⁸⁸
- Co-located projects summing to more than 2 MW of Community Solar may be permissibly located in one of two ways:
 - Two projects of up to 2-MW in size on one parcel or contiguous parcels; or
 - An up to 2-MW project on each of two contiguous parcels.⁴⁸⁹
- A parcel of land may not have been divided into multiple parcels in the two years prior to the project application (for the Adjustable Block Program) or bid (for competitive procurements) in order to circumvent this policy. If a parcel has been divided within that time period, this requirement will apply to the boundaries of the larger parcel prior to its division.
- If there are multiple projects owned or developed by a single entity (or its affiliates) located on one parcel of land, or on contiguous parcels of land, any size-based adders will be based on the total size of the projects owned or developed on the contiguous parcels by that single entity or its affiliates. Furthermore, the total combined size of projects owned or developed by a single entity (or its affiliates) on contiguous parcels of land may not be more than 2 MW, or more than 4 MW if co-located consistent with the provisions outlined above.⁴⁹⁰
 - “Affiliate” means, with respect to any entity, any other entity that, directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with each other or a third entity. “Control” means the possession, directly or indirectly, of the power to direct the management and policies of an entity, whether through the ownership of voting securities, by contract, or otherwise. Affiliates may not have shared sales or revenue-sharing arrangements, or common debt and equity financing arrangements.
 - “Contiguous” means touching along a boundary or a point. For example, parcels touching along a boundary are contiguous, as are parcels that meet only at a corner. Parcels, however near to each other, that are separated by a third parcel and do not touch along a boundary or a point are not contiguous. Additionally, parcels that are separated by a public road, a railroad, or other right of way accessible at all times to the general public are not contiguous.
- Projects owned or developed by separate entities (meaning that they are not affiliates) may be located on contiguous parcels. If there is a naturally good location from an interconnection standpoint, one owner should not be allowed to prevent another owner from developing a project in that location.
- Projects must have separate interconnection points.

⁴⁸⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 131. The Agency’s standard makes minor modifications which the Agency considers to be within the spirit of what was approved in that proceeding, as the Commission’s Order – if read literally – would allow for the co-location of two 2 MW projects, but would prohibit the co-location of two 1.9 MW projects.

⁴⁸⁸ See id.

⁴⁸⁹ See id.

⁴⁹⁰ See id.

Additionally, on May 2, 2018, the Commission entered an Amendatory Order in Docket No. 17-0838 authorizing the IPA to “investigate outside of this docket the probability of cost savings (if any) for co-located projects that puts their average costs below those modeled in the IPA’s REC pricing model, and if warranted based on the results of that investigation, establish a tier in its REC pricing model applicable to co-located systems exceeding 2 MW in aggregate size.”⁴⁹¹ The IPA’s June 4, 2018 REC Compliance Filing containing updated REC values reflects the establishment of a REC pricing model tier applicable to co-located Community Solar systems exceeding 2 MW in aggregate size, and updated prices contained in Section 6.4 also include a separate co-located project pricing tier.

If a single project is developed and then a second, co-located project is developed on the same or a contiguous parcel at a later date, the approach above contemplates that these two projects will be considered co-located and co-located project prices will apply. To make this price adjustment the least administratively burdensome on all parties involved, the price adjustment for both projects will only be applied to the second project, with that project’s REC price reflecting not only the co-located project price, but also an additional discount reflecting the differential between the first project’s contract price and the applicable Block’s co-located project price. This co-located pricing provision will only be applicable if the Commission’s approval of the second project is within one year or less of the Commission approval date of the first project. If the first project has not yet commenced construction at the time of the second project’s approval, then the co-located pricing provision will apply.

In the case that there are two co-located projects on a single parcel (or two contiguous parcels) owned by a single entity or represented by a single Approved Vendor, any sale of one project to a different owner or transfer of one project to a different Approved Vendor would not avoid the price adjustment that applies to co-located projects. In such a case, the second project’s REC price would be adjusted to a price accounting for both co-located projects (i.e., below the listed co-located project price) in line with the description above. This restriction also applies to projects that are accepted off the waitlist that would render an already developed project into a co-located project.⁴⁹²

7.4. Eligibility of Projects Located in Rural Electric Cooperatives and Municipal Utilities

The definition of community renewable generation projects specifically mentions rural electric cooperatives and municipal utilities,⁴⁹³ but does not explicitly include or exclude them from any program or procurement to be run by the Agency. Moreover, the definition includes the concept of that project having “subscribers,” a term which in turn has a definition that defines such “subscribers” as “tak[ing] delivery service from an *electric utility*,” which as defined in the IPA Act does not include cooperative and municipal utilities.⁴⁹⁴ This resulted in ambiguity around whether a community

⁴⁹¹ Docket No. 17-0838, Amendatory Order dated May 2, 2018 at 1-2.

⁴⁹² The Commission affirmed the propriety of this approach through approving the First Revised Plan. See Docket No. 19-0995, Final Order dated February 18, 2020 at 95.

⁴⁹³ See 20 ILCS 3855/1-10 (“‘Community renewable generation project’ means an electric generating facility that is . . . interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act”).

⁴⁹⁴ Specifically, Section 1-10 of the IPA Act defines an electric utility as having “the same definition as found in Section 16-102 of the Public Utilities Act,” which is “a public utility, as defined in Section 3-105 of this Act, that has a franchise, license, permit or right to furnish or sell electricity to retail customers within a service area.” 220 ILCS 5/16-102. Section 3-105 of the PUA in turn defines “public utility” to

renewable generation project can be located within the service territory of a rural electric cooperative or a municipal utility.

The Agency recognized the General Assembly's choice expressly to include those entities in defining "community renewable generation projects"—a term only used in the IPA Act in connection with the Agency's community renewable generation program—and proposed in its Initial Plan that community renewable generation projects (including community solar) located in these service territories should, if possible, be eligible for the Adjustable Block Program and Illinois Solar for All Program (where applicable).

The status of community renewable generation projects and distributed renewable energy generation devices located in the service territories of rural electric cooperatives, municipal electric utilities, and Mt. Carmel Public Utility Company was a contested issue in Docket No. 17-0838. The Commission's Final Order in that proceeding determined that the Agency's Initial Plan correctly allowed the participation of these projects in the Adjustable Block Program, the Community Renewable Generation Program, and the Illinois Solar for All Program.⁴⁹⁵ In June 2018, Commonwealth Edison Company filed a petition seeking review of that determination (i.e., an appeal) with the state's Second District Appellate Court, case number 2-18-0504. On May 2, 2019, the Appellate Court affirmed the ICC's decision in this regard. On July 11, 2019, ComEd filed a Petition for Leave to Appeal, No. 124898, with the Supreme Court of Illinois. It was denied on September 25, 2019, resolving this issue and clarifying that projects in the service territories of rural electric cooperatives, municipal electric utilities, and Mt. Carmel Public Utility Company, are indeed eligible to receive REC delivery contracts under the Adjustable Block Program.

As mentioned above, there are already at least three community solar offerings by or within rural electric cooperatives. Illinois' first community solar project was a 126 kW installation in Elizabeth, built by Jo Carroll Energy in December 2014.⁴⁹⁶ That project allows Jo Carroll customers to buy individual panels in the 460-panel ground-mounted system, with the energy produced credited against their bills. Prairie Power sells kWh blocks of solar power to customers of its 10 distribution cooperatives through the Bright Options Solar program. The program is supplied by two 500 kW solar installations near Shelbyville and Astoria, both built in 2015.⁴⁹⁷ Neither of these projects would be eligible to participate in the Adjustable Block Program because they were energized prior to June 1, 2017, but they indicate that rural electric cooperatives have thus far been the leaders in community solar in Illinois. Several proposed community solar projects that would be located within the Jo Carroll Energy service territory applied to the Adjustable Block Program, and one – the Apple Canyon Lake Solar Farm – was allocated a REC contract via the April 10, 2019 lottery.

The Agency proposes no changes to the standard for allowing community renewable generation projects in the service territories of rural electric cooperatives and municipal utilities to participate in the Agency's programs or procurements from the standard approved by the ICC in the Initial Plan. This standard, outlined below, may require actions be taken by the rural electric cooperative or

expressly *exclude* "public utilities that are owned and operated by any political subdivision, public institution of higher education or municipal corporation of this State, or public utilities that are owned by such political subdivision, public institution of higher education, or municipal corporation and operated by any of its lessees or operating agents" as well as "electric cooperatives as defined in Section 3-119" of the PUA. 220 ILCS 5/3-105.

⁴⁹⁵ See Docket No. 17-0838, Final Order dated April 3, 2018 at 177-179.

⁴⁹⁶ Jo Carroll Energy, <https://www.jocarroll.com/south-view-solar-farm>.

⁴⁹⁷ Prairie Power, <https://www.ppi.coop/brightoptions>.

municipal utility. As entities not regulated by the state, they are free to choose whether to take these actions, but should they choose not to, then the residents and businesses within their service territories would not benefit from receiving revenue through these programs for its RECs, and thus the economics of such projects may not be as attractive to developers or subscribers.

The requirements for participation for a community renewable generation project located in a rural electric cooperative or municipal utility follow from those required in the Act for electric utilities:

- Be capable of “credit[ing] the value of electricity generated by the facility to the subscribers of the facility.”⁴⁹⁸ This can be accomplished though offering “virtual net metering” substantially similar to the provisions contained in Section 16-107.5(I) of the Public Utilities Act.⁴⁹⁹ The value of electricity credited must be at no lower than the subscriber’s supply rate.⁵⁰⁰
- Provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber.⁵⁰¹
- Purchase any unsubscribed energy from community renewable generation projects that are Qualifying Facilities (“QF”) under the electric utility's tariff for purchasing the output from QFs under Public Utilities Regulatory Policies Act of 1978.⁵⁰²

Prior to a photovoltaic community renewable generation project applying for the Adjustable Block Program, or a community renewable generation project powered by other renewable technologies participating in the competitive procurement, the Approved Vendor shall obtain a certification addressed to the Agency that the rural electric cooperative or municipal utility has met these conditions from the subject cooperative or municipal utility. Absent this information, a project located in the service territory of that rural electric cooperative or municipal utility will not be allowed to participate. All other programmatic requirements for community renewable generation projects (e.g., size limits, co-location, consumer protections) would apply to projects located in rural electric cooperatives or municipal utility service territories. For the purposes of rural electric cooperatives, these requirements apply at the distribution cooperative level, rather than for generation and transmission cooperatives (which do not directly interact with retail customers).

7.5. Types of Community Renewable Generation Projects

As noted at the outset of this Chapter, the concept of Community Renewable Generation is still developing within Illinois and nationwide. Practitioners are still developing new business models, and policymakers continue to explore project development models that offer additional, non-transactional attributes or characteristics to achieve additional policy objectives. In some models, customers take ownership of a share of a community project, identifying specific solar panels. In others, the developer owns the project and sells subscriptions for a contractually obligated term, or an indefinite term that can be ended at will. The value of the generation can be conveyed to the

⁴⁹⁸ See definition of “Community Renewable Generation Facility” in 20 ILCS 3855/1-10.

⁴⁹⁹ See 220 ILCS 5/16-107.5(I).

⁵⁰⁰ If the municipal utility or rural electric cooperative does not have unbundled rates (e.g., separate line items for delivery services and electricity supply) then the applicable municipal utility or rural electric cooperative must indicate the portion of the bundled rate that reasonably correlates to the cost of electricity supply service.

⁵⁰¹ See 20 ILCS 3855/1-75(c)(1)(N).

⁵⁰² See id.

customer by virtual net metering (as an energy credit), by a value-of-solar tariff, or as a premium purchase.

One issue that the Agency has considered is the extent to which projects will be proposed by commercial developers who then seek to identify subscribers, and by community-led projects where interested parties in a community come together to seek to develop a project. A church parish, for example, could put photovoltaic panels on the roof of the church, with subscriptions sold to parishioners. In theory, developer-led projects are likely to be larger and located where interconnection costs are minimized, while community-led projects like the church parish could be smaller and face the possibility of higher interconnection costs because the location is determined by community-focused interests rather than pure engineering considerations. But in practice, the wide range of interconnection cost estimates offered to the many large community solar projects that have applied to the Adjustable Block Program generally demonstrate that the drivers of interconnection costs are not the size of the system itself but rather the broader infrastructure to which the project is interconnecting.

Properly defining what is truly a community-led project could be problematic and subject to gaming. It is possible, for example, that community groups will team with professional solar developers to realize their projects, with varying ownership structures. Given the long waitlist of community solar projects that have already applied to the Adjustable Block Program, most of which appear to be developer-driven, the Agency is not proposing any changes (such as a price adder) for community-led projects. As discussed in Section 6.3.3.1, the Agency sought feedback on how to manage that waitlist of community solar projects, and has proposed an approach for new blocks of community solar capacity that may encourage applications from more community-driven projects.

Certain community-led projects may instead be eligible for a higher level of incentives through the Illinois Solar for All Program as described in Chapter 8. Developers of Community Solar projects that participate in that program are required to “identify its partnership with community stakeholders regarding the location, development, and participation in the project, provided that nothing shall preclude a project from including an anchor tenant that does not qualify as low-income. Incentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit organizations, and affordable housing owners.”⁵⁰³

7.6. Subscriber Requirements

With community renewable generation still an emerging concept, the level of consumer interest and the most viable business models remain to be determined. Most offers the Agency has observed in the market to date are simply cost savings offers under which the customer pays a lower per kilowatt hour fee for a community solar subscription than the customer receives as a per kilowatt hour credit through net metering. In general, Agency seeks to allow creativity and flexibility in developing projects and creating unique value propositions for subscribers, while at the same time ensuring basic consumer protections.

⁵⁰³ 20 ILCS 3855/1-56(b)(2)(B).

7.6.1. Small Subscriber Participation

The Act requires that the Agency propose terms and conditions that “ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties.”⁵⁰⁴ Collectively the Agency considers “residential and small commercial customers” to be “small subscribers” so long as their subscription size is below 25 kW. Perhaps notably, the above-quoted language of the Act refers to “robust participation opportunities”⁵⁰⁵ for small customers—and does not mandate robust participation.

To date, as described in Section 6.5 and consistent with the Commission’s Order in Docket No. 17-0838, the Agency has used adders in the Adjustable Block Program to recognize the value of small subscriber subscriptions. The Agency has found that this adder, along with the preference for a small subscriber commitment in the case of a lottery to select community solar projects upon the opening of the Adjustable Block Program (as described in Section 6.3.1),⁵⁰⁶ have been effective mechanisms for ensuring robust participation opportunities for small subscribers. During the litigation of the Initial Plan in Docket No. 17-0838, some stakeholders sought for 25% small customer participation to serve as a useful baseline for measuring small subscriber participation. 98.9% of community solar projects that applied to the program when it opened in early 2019 made a commitment to have *at least 50% small subscribers*, and the Agency is not aware of any evidence at this time that projects selected in the lottery will not fulfill those commitments.

The Agency believes that the initial program design was extremely successful in encouraging small subscriber participation, but cautions most contracted community solar projects are still under development. To date, 93% of the capacity of energized community solar projects has been subscribed by small subscribers. For the purposes of this Second Revised Plan, the Agency is not proposing any changes to its small subscriber requirements (other than any changes to the small subscriber adder explained in Section 6.5.3), but will continue to monitor actual results of small subscriber acquisition as additional projects reach energization.

7.6.2. Marketing to Small Subscribers

Subscribing to a community renewable generation project is not the same as choosing to purchase or lease a system to be located on your own property. It does, however, bear similarities to signing up to take supply service from an Alternative Retail Electric Supplier. The Agency observes that the history of questionable marketing practices of some Alternative Retail Electric Suppliers gives reason to be concerned about the marketing of community renewable generation subscriptions.⁵⁰⁷

⁵⁰⁴ 20 ILCS 3855/1-75(c)(1)(N).

⁵⁰⁵ Emphasis added.

⁵⁰⁶ See also Docket No. 17-0838, Final Order dated April 3, 2018 at 144.

⁵⁰⁷ See, e.g., ICC Docket No. 14-0512, Consumer Services Division and Office of Retail Market Development Staff Report to the Commission dated August 20, 2014, <https://www.icc.illinois.gov/downloads/public/edocket/384622.pdf> (detailing misleading and noncompliant marketing tactics employed by one ARES); ICC Docket No. 15-0438, Consumer Services Division and Office of Retail Market Development Staff Report to the Commission dated July 20, 2015, <https://www.icc.illinois.gov/docket/files.aspx?no=15-0438&docId=232481> (detailing several misleading telephone marketing tactics employed by a different ARES); ICC Docket No. 15-0512, First Notice Order, September 22, 2016, at 55 (expressly relying on information submitted with the ICC Staff Initial Comments dated November 5, 2015 (<https://www.icc.illinois.gov/downloads/public/edocket/417068.pdf>), which detailed trends in allegations of ARES wrongdoing including unauthorized switching, misrepresentation of the nature of the transaction, misrepresentation of identity of the ARES, misrepresentation of price or savings, failure to disclose cancellation fees or right to cancel, and more); ICC Docket No. 17-0273, Order, August 15, 2017, at 4-5 (denying a certificate of service authority to an ARES that, previously operating in Illinois under a prior corporate structure, had amassed numerous complaints related to sales and marketing).

While competition in the natural gas and electricity markets has created many benefits for the residents and businesses of Illinois, those benefits have not been uniform, and in many instances, particularly in residential markets, the benefits have been non-existent; in fact, at times supply offers have been harmful to consumers. This Plan is not the place to have a full debate on acceptable marketing practices, but the Agency would like to highlight past practices that some alternative gas and electric suppliers have engaged in that cause concern for the Agency. These include improperly associating the supplier with the local utility or a government agency or program; implying that a customer must choose to enroll; inflating the price of green energy offers far beyond the actual incremental cost of procuring renewable resources; and targeting elderly, non-English speaking, and/or low-income customers who may have less access to quality information about energy prices.

The Agency recognizes that it may not be able to prohibit door to door, telemarketing, or online sales of community renewable generation subscriptions, but notes those marketing channels as ones of particular concern because of the information asymmetry between the salesperson and the consumer. The Agency believes an informed consumer is a wise consumer and strongly encourages marketing channels that respect the opportunity for consumers to have complete and accurate information about the decisions they may make regarding subscriptions, particularly those related to upfront payments, the net price of energy, and termination fees and conditions. The Agency or its Program Administrators may conduct additional monitoring of Approved Vendors and Designees that utilize door to door, telemarketing, and online sales, and reserve the right to request the Approved Vendor provide additional documentation of those marketing channels including, but not limited to, access to call center recordings for either sales or third-party verifications.

As discussed in Section 6.9.1, all in-person, phone, and online marketing/lead generation firms are required to register as Designees with the Adjustable Block Program, including disclosure by Approved Vendors of all such partners and their direct contact information prior to utilizing their services within the scope of the Adjustable Block Program.

As described in the Initial Plan, there are a number of state and federal consumer protection laws, regulations, and enforcement agencies that apply to all forms of marketing, including marketing of subscriptions to Community Renewable Generation Projects.⁵⁰⁸

⁵⁰⁸ Diana Chace and Nate Hausman, Clean Energy States Alliance, *Consumer Protection for Community Solar: A Guide for States*, June 8, 2017. <http://cesa.org/resource-library/resource/consumer-protection-for-community-solar-a-guide-for-states>.

Table 7-1: Federal Statutes that Apply to Community Solar

Statute	Topic
CAN-SPAM Act	Electronic marketing
Consumer Leasing Act	Leasing disclosures
Electronic Funds Transfer Act	Consumer rights in electronic fund transfers
Equal Credit Opportunity Act	Discrimination in credit transactions
Fair Credit Reporting Act	Collection and use of consumer information
Federal Trade Commission Act	Unfair and deceptive trade practices
Magnuson-Moss Warranty Act	Consumer product warranties
Right to Financial Privacy Act	Financial privacy from government intrusion
Truth in Lending Act	Lending disclosures and standardization
Telephone Consumer Protection Act	Telemarketing and automated telephone
Unfair Deceptive Practices Act (UDAAP)	Misleading financial products and services
Uniform Commercial Code	Sales and commercial transactions

Source: CESA, *Consumer Protection for Community Solar: A Guide for States*, 2017.

Table 7-2: Illinois Statutes that Apply to Community Solar

Statute	Topic
Consumer Fraud and Deceptive Business Practices Act (815 ILCS 505)	Enrollment, marketing, billing, and collection by electric service providers
Electronic Mail Act (EMA) (815 ILCS 511)	Regulates e-mail solicitations
Telephone Solicitations Act (815 ILCS 413) and the Restricted Call Registry Act (815 ILCS 402)	Regulates telemarketing practices
Personal Information Protection Act (815 ILCS 530)	Requires companies that collect personal information to take reasonable measures to protect it and report unauthorized access to consumer’s personal information.

These laws and regulations provide a starting point for protecting consumers, but their enforcement agencies typically only track and enforce violations if triggered by consumer complaints. In order to ensure that subscribers are well-informed and thus afforded adequate consumer protections, the Agency will require that all projects adhere to the following terms and conditions for subscriptions.

Drawing from the consumer protection guidelines for community solar adopted by the Maryland Public Service Commission, the Agency requires that Approved Vendors seeking REC delivery contracts associated with Community Renewable Generation Facilities participating in the Adjustable Block Program or in Illinois Solar for All must include each of the following in any contracts entered into by that Approved Vendor or its Designees with subscribers:

- (a) A plain language disclosure of the subscription, including:
 - (i) The terms under which the pricing will be calculated over the life of the contract and a good faith estimate of the subscription price expressed as a monthly rate or on a per kilowatt-hour basis;
 - (ii) Whether any charges may increase during the course of service, and, if so, how much advance notice is provided to the subscriber.
- (b) Contract provisions regulating the disposition or transfer of a subscription;
- (c) All nonrecurring (one-time) charges;
- (d) All recurring (monthly, yearly) charges;
- (e) A statement of contract duration, including the initial time period and any rollover provision;
- (f) Terms and conditions for early termination, including:
 - (i) Any penalties that the Project Developer may charge to the subscriber; and
 - (ii) The process for unsubscribing and any associated costs.
- (g) If a security deposit is required:
 - (i) The amount of the security deposit;
 - (ii) A description of when and under what circumstances the security deposit will be returned;
 - (iii) A description of how the security deposit may be used; and
 - (iv) A description of how the security deposit will be protected.
- (h) A description of any fee or charge and the circumstances under which a customer may incur a fee or charge;
- (i) A statement explaining any conditions under which the Project Developer may terminate the contract early, including:
 - (i) Circumstances under which early cancellation by the Project Developer may occur;
 - (ii) Manner in which the Project Developer shall notify the customer of the early cancellation of the contract;
 - (iii) Duration of the notice period before early cancellation; and
 - (iv) Remedies available to the customer if early cancellation occurs;
- (j) A statement that the customer may terminate the contract early, including:
 - (i) Amount of any early cancellation fee;
- (k) A statement describing contract renewal procedures, if any, including any automatic renewal provisions;
- (l) A dispute procedure;
- (m) The Agency's and Commission's phone number and Internet address;
- (n) A billing procedure description;
- (o) The data privacy policies of the Project Developer;
- (p) A description of any compensation to be paid for underperformance;
- (q) Evidence of insurance;
- (r) A description of the project's long-term maintenance plan;
- (s) Current production projections and a description of the methodology used to develop production projections;
- (t) Contact information for the Project Developer for questions and complaints;
- (u) A statement that the Project Developer does not make representations or warranties concerning the tax implications of any bill credits provided to the subscriber;

- (v) The method of providing notice to the subscribers when the project is out of service for more than three business days, including notice of:
 - (i) The estimated duration of the outage; and
 - (ii) The estimated production that will be lost due to the outage.
- (w) Any other terms and conditions of service.

The Agency may also develop additional terms and conditions in the general course of developing program requirements, but will seek stakeholder feedback prior to doing so. As referenced above, the Agency and its Procurement Administrator have developed Standard Disclosure Forms for use in the marketing of community renewable generation project subscriptions, and the Agency has attempted to draw upon many of these same concepts in its Standard Disclosure Forms to ensure that key subscription terms are clearly disclosed to potential subscribers.

On the topic of ARES marketing, in its Spring 2019 legislative session, the Illinois General Assembly passed Senate Bill 651, which was then signed into law by the Governor on August 27, 2019.⁵⁰⁹ That Act codifies certain ARES consumer protections around (among others) marketing conduct and automatic renewal already contained in Illinois Commerce Commission rules and introduces new consumer protections, including restrictions around enrolling low-income customers and a ban on termination fees for residential and small commercial customers.

The Agency is confident that the expressed will of the General Assembly supports the intent consistently expressed in the Agency's Plans seeking to hold community solar marketers to the highest standards of consumer protection. The Agency updated its Marketing Guidelines (and, other program documents and requirements) in light of Public Act 101-0590 and the specific issues which that legislation seeks to address.

In addition, to ensure portability and transferability of subscription contracts, as required by Section 1-75(c)(1)(N) of the Act, any such contract should provide that the subscriber (i) may retain the subscription (or at least a downsized version of the subscription relative to the subscriber's new load) as long as the subscriber changes addresses for utility service within the same utility service territory, and (ii) may assign or sell the subscription to another person within the same utility service territory, without any fee owed to the subscription counterparty, subject to reasonable terms and conditions including matching the subscription size to the new subscriber's load. The Agency understands that the community renewable net metering tariffs for Ameren Illinois, ComEd, and MidAmerican approved by the Commission on September 27, 2017 are consistent with these principles. This is also consistent with guidance on this topic already published by the Program Administrator on the Program's consumer-facing website on October 3, 2019.⁵¹⁰

7.6.3. Marketing Claims Related to the Ownership of RECs and Community Renewable Generation Subscriptions

The Agency's Adjustable Block Program for community solar and the competitive procurement for other forms of community renewable generation are both based on the core requirement that the value to the project developer (and in turn the ability to make a financially attractive offer to subscribers) is based upon the sale of the project's environmental attributes (in the form of RECs)

⁵⁰⁹ See 101st Illinois General Assembly, Public Act 101-0590, <http://www.ilga.gov/legislation/publicacts/101/PDF/101-0590.pdf>

⁵¹⁰ See <http://illinoisshines.com/faq> ("If I subscribe to a community solar project participating in the Adjustable Block Program, can I keep my subscription when I move? Can I transfer my subscription to someone else?").

from the project to a utility. Those RECs are then retired by the utility to meet the annual RPS goals of that utility, and the original REC holder's claims to those environmental attributes are effectively extinguished through that sale.

This raises the issue of what marketing claims may be made related to a subscription in a community renewable generation project receiving a REC contract (including community solar projects participating in the Adjustable Block Program), as such projects will have already contractually committed the sale of their environmental attributes to a third party. With the underlying "renewable" or "solar" element of that generation having been decoupled and sold to the utility, can it still be marketed as a "community solar" project? Moreover, can the subscriber make any claims for any commercial purpose about any "green" (or similar) aspect of his or her energy sourcing?

Guidance from the Federal Trade Commission ("FTC") would appear to limit what claims can be made about energy sourced from projects whose RECs are transferred to another entity.⁵¹¹ That guidance suggests that appropriate disclaimers about the fate of the RECs may satisfy rules against deceptive marketing. Yet, at some point, the issue begins to border on the absurd: a lengthy factual explanation of a community solar subscription and this Agency's various RPS programs would be permissible, but a shorthand description used to market that subscription may be legally problematic.

While the Agency recognizes that it is not the Federal Trade Commission (or the state's Office of Attorney General) and thus cannot provide reliable guidance on what marketing claims may be legally permissible, the Agency can play an important role in ensuring that any potential subscribers understand the value of a community solar subscription (or that any potential onsite hosts understand the value of an onsite installation)—even if more direct statements cannot be made about the environmental attributes of the underlying energy. To this end, the Agency has worked with its Adjustable Block Program Administrator on the development of a "brand" associated with Adjustable Block Program participation, "Illinois Shines." The Illinois Shines "brand," and associated content (including the public-facing web site <http://illinoisshines.com>) allows potential subscribers to a community solar project (or home and building owners seeking to install onsite solar) to understand that participation in such a project helps the state meet its renewable energy goals and may support the development of a new generating facility—but without risking the project developer itself making arguably false or misleading claims about "renewable" or "clean" energy.

The Agency plans to continue to work closely with representatives of the solar industry, the state's Office of the Attorney General, the Staff of the Illinois Commerce Commission, and other parties in continuing to refine this approach and any associated content. This includes adding additional consumer-facing educational and informational content to the program website.

7.7. Utility Responsibilities

While the Agency, through the Adjustable Block Program and competitive procurements, will be responsible for the procurement of RECs from community renewable generation projects, it is not responsible for all aspects of a successful program. There are several additional key aspects of making community renewable generation projects successful that fall outside of the control of the Agency.

See 16 C.F.R. § 260.15(d), Example 5; see also U.S. EPA, "Making Environmental Claims," <https://www.epa.gov/greenpower/making-environmental-claims>; see also U.S. FTC letter dated February 5, 2015, https://www.ftc.gov/system/files/documents/public_statements/624571/150205gmpletter.pdf.

- The crediting of the value of energy through net metering
- Ensuring the portability and transferability of subscriptions within a utility service territory.

The Agency will work with system owners and developers as well as the utilities (and with rural electric cooperatives and municipal utilities should they choose to participate) to reflect these aspects in the terms, conditions, and operational aspects of the programs and procurements conducted by the Agency. The Agency will also coordinate with the utilities for the sharing of any pertinent data and information that each party collects and maintains regarding projects and subscriptions.

Public Act 99-0906 required each electric utility to file a tariff within 90 days after the Act's effective date, June 1, 2017, to implement net metering for community renewable projects.⁵¹² A brief summary of those filings (and the resultant proceedings, where applicable) is outlined below.

ComEd's community renewable generation net metering tariff, Rider POGCS, was approved by the Commission in Docket No. 17-0350 on September 27, 2017. The Commission resolved a dispute between the Company and intervenors around indemnification by approving ComEd's proposal that both subscribers and the project itself will indemnify the Company against any liabilities relating to the reporting of a subscriber's share or a subscriber's interval usage data – and that ComEd will not have reciprocal indemnification obligations. The Commission indicated that existing regulations related to billing and meter usage data would be “more than sufficient to ensure that ComEd complies with its legal obligations.”⁵¹³ The Commission rejected the proposal of certain intervenors that the net metering credit paid to community renewable generation projects include the volumetric transmission services charge, in addition to the supply charge (which includes an adjustment factor).

MidAmerican's community renewable generation net metering tariff, Rate NM, was approved by the Commission in Docket No. 17-0368 on September 27, 2017. The tariff stipulates that both subscribers and the project itself will indemnify the Company against any liabilities relating to the reporting of a subscriber's share or a subscriber's interval usage data. MidAmerican's tariff provides community renewable net metering credits at the “supply charge,” plus certain adjustment factors.

Ameren Illinois proposed revisions to its existing net metering tariff, Rider NM, to include provisions for community renewable generation project net metering. The revisions were approved by the Commission on September 27, 2017. Ameren Illinois' revised tariff credits the energy service bills of subscribers to a community renewable generation project for net production at the “tariffed or contract rate for electricity supply as appropriate.”

As discussed in Section 7.6.2, the Agency understands that the three approved tariffs allow portability and transferability of subscriptions, as required by Section 1-75(c)(1)(N) of the Act.

⁵¹² 220 ILCS 5/16-107.5(l), (l-5).

⁵¹³ Docket No. 17-0350, Final Order dated September 27, 2017 at 18.

8. Illinois Solar for All Program

8.1. Overview

The Illinois Solar for All Program was created through revisions to Section 1-56(b) of the IPA Act contained in Public Act 99-0906 to “include incentives for low-income distributed generation and community solar projects” with the following objectives:

“bring photovoltaics to low-income communities in this State in a manner that maximizes the development of new photovoltaic generating facilities, to create a long-term, low-income solar marketplace throughout this State, to integrate, through interaction with stakeholders, with existing energy efficiency initiatives, and to minimize administrative costs.”⁵¹⁴

The Act creates four sub-programs within Illinois Solar for All, with incentives for each type of development:

- (A) Low-income Distributed Generation, for on-site solar projects
- (B) Low-Income Community Solar, for off-site solar projects
- (C) Incentives for non-profits and public facilities to do on-site projects
- (D) Low-Income Community Solar Pilot Projects, with distinct rules and incentives

The Agency is instructed to “include a description of its proposed approach to the design, administration, implementation and evaluation of the Illinois Solar for All Program” in this Plan. This Chapter fulfills that provision of the Act.

While the price of photovoltaics has declined dramatically over recent years, there can be significant upfront costs for the development of projects. The financial incentives offered through the Adjustable Block Program may not be sufficient for low-income households and communities to overcome the substantial barriers to participating in the growing solar energy market. The Illinois Solar for All Program is an alternative approach and program to help address this challenge.

8.2. Design Considerations

In developing the program, the Agency identified two key design elements for implementing the Illinois Solar for All Program that necessitated more focused discussion: the relationship to the Adjustable Block Program, and the creation of economic benefits for participants.

8.2.1. Relationship with the Adjustable Block Program

The goals of the Illinois Solar for All Program overlap with the goals of the Adjustable Block Program in that both promote distributed photovoltaic generation and community solar. The differences primarily involve the sectors that the programs serve, the structure of the incentives and program design, and the applicable funding sources.

As described in this Chapter, the Agency administers the Illinois Solar for All Program separately from the Adjustable Block Program, but it is built off of the program design of the Adjustable Block

⁵¹⁴ 20 ILCS 3855/1-56(b)(2).

Program, with additional considerations specific to Illinois Solar for All. These include a different level of incentives, additional requirements to be an Illinois Solar for All Approved Vendor, additional project application requirements, Illinois Solar for All specific contracts, and additional considerations to ensure community involvement, consumer protections, and eligibility. To the extent not specifically mentioned in this Chapter, the program design, terms, and conditions of the Adjustable Block Program also apply to the administration of, and REC delivery contracts executed under, the Illinois Solar for All Program.

The exception to this principle is the Low-Income Community Solar Pilot Project sub-program; this sub-program operates under an entirely different project selection structure (featuring a competitive procurement process), and as discussed in the Initial Plan, the Agency has funded this sub-program solely through the Renewable Energy Resources Fund.

8.2.2. Economic Benefits

The second consideration is the concept of “economic benefits” and how low-income participants can capture them. The Act stipulates that for the Illinois Solar for All Program, “[e]ach contract that provides for the installation of solar facilities shall provide that the solar facilities will produce energy and economic benefits, at a level determined by the Agency to be reasonable, for the participating low income customers.”⁵¹⁵ In addition, contracts should “ensure [that] the wholesale market value of the energy is credited to participating low-income customers or organizations and to ensure tangible economic benefits flow directly to program participants, except in the case of low-income multi-family housing when the low-income customer does not directly pay for energy.”⁵¹⁶ For the purposes of this chapter the term “multi-family” applies to residential buildings with five or more units.

A key barrier to low-income participation in renewable energy programs is lack of access to funds and financing to pay for the up-front costs of photovoltaic systems.

To create “tangible economic benefits” at a “reasonable” level, the Agency has determined that eligible residential participants in the Illinois Solar for All Program should not have to pay up-front costs for on-site distributed generation, or pay an up-front fee to subscribe to a community solar project.⁵¹⁷ Further, participation in the program should result in immediate, reliable reductions in energy costs for those residents or subscribers. Consistent with the Commission’s Order in Docket No. 17-0838, this means that for projects that are financed or leased, any ongoing annual payments must be smaller than 50% of the annual first year estimated production and/or utility default service net metering value to be received by the customer.⁵¹⁸

For this draft Second Revised Plan, the Agency proposes that an exception to this no up-front costs standard be made for multi-family Low-income Distributed Generation projects where the participant purchases the system. In this case, the residential participant’s first-year savings may be less than 50% so long as the calculation of that customer’s expected ongoing

⁵¹⁵ 20 ILCS 3855/1-56(b)(2).

⁵¹⁶ Id.

⁵¹⁷ This requirement does not apply to multi-family buildings with more than five units, or projects in the non-profit/ public facilities sub-program.

⁵¹⁸ See Docket No. 17-0838, Final Order dated April 3, 2018 at 151. As required by the Commission’s Order, this calculation must be “disclosed to the customer and reviewed and approved by the Agency.”

savings demonstrates that this requirement would be met through overall savings applied across the full 15 years of the REC delivery contract. The Agency is interested in stakeholder feedback on whether there should be a cap on up-front costs for this situation, and if so, at what amount.

The Agency requires that Illinois Solar for All Approved Vendors verify that developers, installers, landlords, and other intermediaries ensure that the resulting value of the incentives offered by the program flow through to the people the program is meant to serve. However, the Agency notes that in order to avoid an overly complex administrative system, incentive levels are not customized to each participant's specific economic circumstances.

For public and non-profit facilities that participate in the Illinois Solar for All Program, the Agency proposes to continue to utilize an approach in which the incentive level recognizes that these entities may not be able to capture the tax benefits that would be available to a comparable sized project participating in the Adjustable Block Program.⁵¹⁹ The higher REC price offered by the Illinois Solar for All Program can help overcome the financing barriers that certain non-profits and public facilities may face compared to private entities. The Agency observes that over 180 non-profit and public facility projects (totaling 60 MW of capacity) have applied to the Adjustable Block Program, indicating that many such projects are viable at the REC prices offered by that program.

In order to account for these additional tax benefits, in the First Revised Plan the Agency proposed that Approved Vendors submitting projects for non-profit or public facilities that *can* utilize the federal Investment Tax Credit under 26 U.S.C. § 48 will be required to demonstrate additional value to the project host. The Agency will maintain that approach for this Second Revised Plan, as discussed further in Section 8.6.3 below.

Ensuring that “the wholesale market value of energy is credited to participating low-income customers” can be achieved through existing net metering provisions. Therefore, projects are required to participate in the applicable utility's or ARES's net metering program. This may prevent projects in the service territory of a municipal utility or rural electric cooperative that does not offer net metering from participating in the Illinois Solar for All Program. The Agency hopes that such municipal utilities and rural electric cooperatives strongly consider adopting net metering policies to bring the full value of solar to their residents and members.

Ensuring that tangible economic benefits flow directly to program participants can also be accomplished by providing documentation to the Agency that a project on a one to four-unit residential building has no upfront cost to the residential participant, except in cases of system purchases; that the value of incentives are used by the project developer/installer to offset costs to the participant; and that there will not be ongoing costs or fees to the participant that exceed 50% of the value of energy produced. The resulting economic benefits to program participants will be accrued through the value they receive through net metering or avoided consumption from the energy the system produces. As described in Section 8.1.1, Illinois Solar for All Approved Vendors are required to document how they ensure that this goal is met. The case of low-income multi-family housing can be more complex and is discussed in more detail in Section 8.6.1.

⁵¹⁹ See Appendix E-5 to Initial Plan, available at <https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/AppendixE-5ILSolarAllNon-ProfitPublicFacilitiesPricingModel.xls>, at “CREST Inputs” tab, cell G73.

It should be noted that these incentives are tied directly to creating economic benefits through lowered net energy costs and are calculated in that manner. As a result, there may be additional costs required to make a specific project viable (e.g., costs associated with roof repairs or wiring upgrades) that these incentives may not be able to address. Additional incentives to pay for those types of separate costs are not available through the Illinois Solar for All Program, and the Agency encourages participants to explore alternative sources of funding as needed. The Agency and the Illinois Solar for All Program Administrator will work with Illinois Solar for All Approved Vendors to facilitate informing and educating program participants about opportunities that may be available to them through utility-administered energy efficiency programs, weatherization assistance programs, lead abatement programs, and other forms of support. This includes the provision of a Program Resource Guide on those programs.⁵²⁰

Additionally, in order to facilitate the direct flow of tangible economic benefits to low-income residential participants, the Agency and its Illinois Solar for All Program Administrator will explore, and if deemed feasible and prudent, pursue the possibility of receiving guidance from the United States Department of Housing and Urban Development that would clarify the treatment of Illinois Solar for All benefits with regard to cost allowance-based low-income housing programs.

8.3. Program Launch

In implementing the various new programs and procurements mandated by Public Act 99-0906, the Agency had a large and varied set of new tasks to undertake. The Agency appreciates the strong interest in the Illinois Solar for All Program and desire to make the benefits of the Program available to low-income households and communities so that they can benefit from lower energy costs. The Illinois Solar for All Program as proposed mostly builds on the Adjustable Block Program described in Chapter 6; therefore, it was necessary to first have the Adjustable Block Program's design finalized and put into operation before the Illinois Solar for All Program was able to launch. Like with the Adjustable Block Program, while the Initial Plan and First Revised Plan detailed many programmatic considerations, final program design including contracts, program manuals, etc. needed to be developed and finalized by the Agency and the Illinois Solar for All Program Administrator(s) prior to program launch.

In November 2018, the Agency and Program Administrator initiated a series of stakeholder engagement sessions to share draft program details with the public and invite written feedback, which was considered in planning the implementation of the Illinois Solar for All Program. Stakeholder feedback sessions were held on a number of topics, including Environmental Justice Communities, Job Training, Approved Vendor Registration, Grassroots Education, Third Party Program Evaluation, Consumer Protection, and Project and Participant Eligibility. These opportunities to engage the public helped ensure that the process of finalizing program protocols and requirements was transparent and responsive to input from stakeholders from the solar industry, environmental advocates, and low-income advocates.

The program began accepting applications for registering ILSFA Approved Vendors on February 19, 2019 and opened for project applications on May 15, 2019. Due to anticipated high interest in the program's incentives for new low-income solar installations, the program launch included an initial project application window for the 2018-2019 program year of 30 days for Low-Income Community

⁵²⁰ See: <https://www.illinoisfsfa.com/app/uploads/2019/03/ILSFA-Program-Resources-Guide-v1-20190318.pdf>.

Solar projects and 45 days for Low-Income Distributed Generation and Non-Profit/Public Facilities projects. 45 Low-Income Community Solar applications (totaling nearly 60 MW of capacity), 28 Non-Profit/Public Facilities applications (totaling over 3 MW of capacity), and 1 Low-Income Distributed Generation application (2 MW of capacity) applied during that initial window. The applications for Low-Income Community Solar and Non-Profit/Public Facility projects exceeded allocated sub-program budgets for the program year, while the Low-Income Distributed Generation sub-program featured application levels below the allocated sub-program budget. Five Low-Income Community Solar projects (totaling 4 MW of capacity), and 7 Non-Profit/Public Facility projects (1.3 MW of capacity) were selected. The community solar projects were selected using the project selection protocol (as discussed further in Section 8.12.2) while all the eligible Non-Profit/Public Facility projects were selected (the volume of project applications in that sub-program dropped below the annual sub-program budget after some were deemed ineligible during review). The one distributed generation applicant project withdrew. In the latter two sub-programs, unused 2018-2019 sub-program budget was rolled over to the respective 2019-2020 sub-program budget.

For the 2019-2020 Program Year, 30 Low-Income Community Solar projects (54.5 MW), 20 Non-Profit/Public Facilities projects (2.7 MW), and 11 Low-Income Distributed Generation projects (2 MW) applied during the initial project application window. Eligible applications for Low-Income Community Solar projects exceeded the allocated sub-program budget for that program year, so the project selection protocol was executed for the Low-Income Community Solar sub-program. Four community solar projects were selected (totaling 4 MW of capacity). The Non-Profit/Public Facilities sub-program reopened on October 25, 2019 for rolling project applications and closed on February 26, 2020 after 24 projects (totaling 2.8 MW of capacity) were approved for the program year. Applications for the Low-Income Distributed Generation sub-program did not fill available the available budget and that sub-program reopened for rolling project applications on October 1, 2019. One multi-family (2 MW) and nine single-family distributed generation projects (totaling 58 kW) were approved by the ICC before the program closed on May 31, 2020.

For the 2020-2021 Program Year, 17 Low-Income Community Solar projects (over 35 MW), 33 Non-Profit/Public Facilities projects (4.9 MW), and 7 multi-family unit (0.354 MW) were submitted during the initial project application windows. Eligible applications for Low-Income Community solar projects exceeded the allocated sub-program budget for the program year, so the project selection protocol was executed for the Low-Income Community Solar program. Three community solar projects were selected (totaling 4.5 MW of capacity). Eligible applications for the Non-Profit/Public Facilities sub-program also exceeded the allocated sub-program budget for the program year, so the project selection protocol was executed and 18 projects (2.4 MW) were selected, and an additional project (0.3 MW) from the waitlist was able to be approved when funding was made available following a project withdrawal from the program. Again, applications for the Low-Income Distributed Generation sub-program did not fill the available budget and reopened for rolling project applications on July 20, 2020. A total of 9 multi-family units (0.424 MW) and 53 single-family distributed generation projects (0.295 MW), totaling 0.719 MW, were approved by the ICC before the program year closed on May 31, 2021.

For the 2021-2022 Program Year, 23 Distributed Generation Projects (21 single-family and 2 multi-family) have applied as of August 16, 2021 and the sub-program remains open for project applications. 48 Non-Profit/Public Facilities Projects (5.8 MW) applied during the initial application window and eligible applications exceeded the allocated sub-program budget for the program year.

Project selection occurred on August 11, 2021 and 20 Projects (2.4 MW) were selected (two projects had incentive values larger than the remaining funds and will need to resize their projects or accept a lesser incentive value). As of the release of this draft Second Revised Plan, the Illinois Solar for All Program Administrator is preparing contracts for those projects for Commission approval. The program year application window for low-income community solar project applications will open on August 23, 2021 and culminate in project selection on October 27, 2021.

8.4. Funding and Budget

The Illinois Solar for All Program is funded through three sources. First, the Renewable Energy Resources Fund pursuant to Section 1-56(b)(2) of the IPA Act; second, funds from the renewable energy resources budgets of the utilities pursuant to Section 1-75(c)(1)(O) of the IPA Act; and third, potential additional funds from the renewable resources budgets of the utilities pursuant to Section 16-108(k) of the Public Utilities Act.

8.4.1. Renewable Energy Resources Fund Funding Available

While Section 1-56(b)(2) envisions the Illinois Solar for All Program being funded primarily through the Renewable Energy Resources Fund, as of August 16, 2021, the balance of the Renewable Energy Resources Fund is \$ 8,067,676.78 (not including \$132.5 million that has been lent to the state's General Revenue Fund and Health Insurance Reserve Fund as discussed below), while existing commitments from the Fund for contracts from the Supplemental Photovoltaic Procurements total \$6.7 million⁵²¹ and for Illinois Solar for All from the first three program years, \$40.7 million. This implies \$93.2 million of RERF funds remain available for Illinois Solar for All. Prior to the 2018-2019 program year (i.e. at the outset of the Program), before the Agency had paid any administrative costs to its Program Administrator, \$150.0 million of RERF funds were available for Illinois Solar for All; this is the figure the Agency will use in this Section in explaining sub-program allocations from the RERF.

Two transfers of \$10 million were made in 2020, one to the General Revenue Fund and one to the Health Insurance Reserve Fund. As with the prior-transferred amount, these transfers are still required to be repaid back into the RERF, and that funding remains available for supporting expenditures from the RERF.

Prior to the enactment of Public Act 99-0906, the Renewable Energy Resources Fund received Alternative Compliance Payments each fall from Alternative Retail Electric Suppliers as part of their RPS compliance obligations. Under the revisions to Section 16-115D of the PUA contained in Public Act 99-0906, those payments were no longer made to the Fund as of June 1, 2017; rather, they were now made to the utilities, and were to be paid to the utilities through Fall 2019.⁵²² With those payments no longer being made into the RERF, there is no new revenue that will be deposited into the Fund.

The RERF's current low balance is due to the fact that on August 10, 2017, \$150 million was transferred from the Renewable Energy Resources Fund to the General Revenue Fund pursuant to

⁵²¹ The commitments consist of REC delivery contracts previously entered into and are being paid, or will be paid, over a five-year REC delivery schedule (invoiced quarterly) depending on when individual systems under contract were completed and began REC deliveries.

⁵²² See 220 ILCS 5/16-115D(i); after May 31, 2019, the ARES will no longer have any future Alternative Compliance Payment obligations, although "alternative retail electric suppliers and electric utilities operating outside their service territories shall be obligated to make all alternative compliance payments that they were obligated to pay for periods through and including May 31, 2019, but were not paid as of that date." Those payments are due to by September 1, 2019.

the borrowing provisions contained in Section 5h.5 of the State Finance Act.⁵²³ \$37.5 million was paid back into the RERF in April of 2019,⁵²⁴ and the remainder of borrowed funds are required by law to be paid back to the Renewable Energy Resources Fund within five years (i.e., by August 10, 2022).⁵²⁵ As described above, two additional transfers of \$10 million were also made in 2020 under this same authority.

Section 5h.5(b) contains a provision that when the RERF (or for that matter other state funds that had similar transfers),

ha[s] insufficient cash from which the State Comptroller may make expenditures properly supported by appropriations from the fund, then the State Treasurer and State Comptroller shall transfer from general funds to the fund only such amount as is immediately necessary to satisfy outstanding expenditure obligations on a timely basis.

Likewise, that Section also provides for,

continuing authority for and direction to the State Treasurer and State Comptroller to reimburse the funds of origin from general funds by transferring to the funds of origin, at such times and in such amounts as directed by the Comptroller when necessary to support appropriated expenditures from the funds, an amount equal to that transferred from them plus any interest that would have accrued thereon had the transfer not occurred...

Were the RERF balance insufficient for payments under any new contractual obligations, these provisions would allow the Agency to make expenditures from the RERF prior to the repayment of the transferred amount—i.e., to operate as though the RERF's balance were at its original amount, even if transferred funds have not yet been moved back into the RERF. In addition, the Agency understands that the State Comptroller will coordinate with the Agency to make sure that any appropriated expenditures that the Agency makes through new contractual commitments are honored by ensuring that the balance of the RERF is at all times sufficient to make timely payments on contracts. While the Agency understands that these transfers from the RERF have caused consternation, based on the assurances contained in the law, it does not believe that these transfers necessitate any adjustments to its proposed Solar for All program design, structure, and budget.

For the Low-Income Distributed Generation Initiative, the Low-Income Community Solar Project Initiative, and Incentives for Non-Profits and Public Facilities sub-programs the Agency plans to allocate up to \$16.5 million per program year from the RERF for use for the Illinois Solar for All Program (the Low-Income Community Solar Pilot Projects sub-program is conducted through a different process that allocates funds to each procurement event rather than program year).⁵²⁶ In the First Revised Plan, the Agency clarified that this allocation will be on an accrual basis, meaning that the amount allocated sets aside that much funding for selected applications during that program year, but are likely to actually be expended in future years in many cases due to the development timeline

⁵²³ 30 ILCS 105/5h.5(b);

⁵²⁴ <https://illinoiscomptroller.gov/financial-data/state-revenues/by-fund/?FundSel=0836&FundGrpSel=&FundCatSel=&FundTypeSel=&GroupBy=Agcy&FY=18&ShowMo=Yes&submitted>.

⁵²⁵ Section 5h.5 was initially created by Public Act 100-0023 and set the repayment time at two years from initial transfer. This transfer-back deadline was subsequently amended to four years by Public Act 101-0010 and then to five years by Public Act 102-0016.

⁵²⁶ As stated in Section 2.6.1, a program year for ILSFA corresponds to an energy delivery year and thus starts June 1 of each year. Therefore, a program year starts one month earlier than the state fiscal year, which begins July 1.

of photovoltaic projects (RECs are paid for upon energization). Unallocated RERF funds from any program year for a given sub-program would roll over and increase the balance available for the subsequent program year for that sub-program.

Table 8-1: RERF Funding for Solar for All⁵²⁷

Funding Source	Low-Income Distributed Generation Incentive	Low-Income Community Solar Project Initiative	Incentives for Non-Profits and Public Facilities	Low-Income Community Solar Pilot Projects
RERF Allocation Percent	22.5%	37.5%	15%	25%
Total RERF Allocation (\$)	\$33,750,000	\$56,250,000	\$22,500,000	\$37,500,000
Previously allocated* for 2018-2019 through 2021-2022 Program Years ⁵²⁸	\$18,000,000	\$30,000,000	\$12,000,000	(\$20 million allocated to 2019 procurement, balance for a 2022 or 2023 procurement)
Allocated* for 2022-2023 Program Year	\$4,950,000	\$8,250,000	\$3,300,000	
Allocated* for 2023-2024 Program Year	\$4,950,000	\$8,250,000	\$3,300,000	

* RERF funds not allocated within a sub-program for a program year will roll over to the next program year for that same sub-program.

Allocations are based on \$150 million of the RERF available for Solar for All at the time of the Initial Plan development, and assume continuing level support from the RERF for the three non-pilot sub-programs in the 2022-2023, 2023-2024, and 2024-2025 program years (which, if fully allocated, would eventually deplete the RERF, leaving only utility-supplied funding available for program years after 2024-2025).

The funds allocated from the RERF are allocated according to the percentages specified in Section 1-56(b)(2) of the Act, namely 22.5% for the Low-Income Distributed Generation Incentive sub-program, 37.5% to the Low-Income Community Solar Project Initiative sub-program, 15% for the Incentives for non-profits and public facilities sub-program, and 25% for the Low-Income Community Solar Pilot Projects sub-program. While the Act includes an all-time cap of \$50 million for the Low-Income Community Solar Pilot Projects, the 25% of available RERF funds is in fact closer to \$37.5 million. As discussed further in Section 8.6.4, the Agency set a budget of \$20 million for the first Low-Income Community Solar Pilot Project procurement held in December 2019; this budget is intended to cover the full 15-year value of contracts resulting from that procurement, although the contracts will be paid out continuously over time rather than upfront.

After accounting for all payments under the Supplemental Photovoltaic Procurement process pursuant to Section 1-56(i) of the IPA Act, as well as all payments under Illinois Solar for All contracts, whenever the balance of the RERF falls under \$5,000, then the RERF shall be inoperative and any remaining funds shall be transferred to the Supplemental Low-Income Energy Assistance Fund for

⁵²⁷ The annual RERF sub-program budgets stated above are gross budgets *before* deducting administrative, evaluation, & grassroots education costs; the budgets actually available for REC incentives will be net of those costs.

⁵²⁸ \$7,273,296 of RERF allocations from the 2018-2019 through 2020-2021 program years was not allocated to projects and is available during the 2021-2022 program year and if not allocated would be further rolled over to the 2022-2023 program year.

use in the Low-Income Home Energy Assistance Program, as authorized by the Energy Assistance Act.⁵²⁹

8.4.2. Utilities Annual Funding Available

Section 1-75(c)(1)(0) contains a provision that

The long-term renewable resources procurement plan shall allocate 5% of the funds available under the plan for the applicable delivery year, or \$10,000,000 per delivery year, whichever is greater, to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or \$20,000,000 per delivery year, whichever is greater, and \$10,000,000 of such funds in such year shall be used by an electric utility that serves more than 3,000,000 retail customers in the State to implement a Commission-approved plan under Section 16-108.12 of the Public Utilities Act.

As discussed in Section 2.2.5.3, the Agency understands “funds available under the plan” in the above statutory provision to refer to funds collected by utilities through RPS riders under Section 1-75(c)(6) of the Act and Section 16-108(k) of the PUA. The following table lists projected amounts of utility funding that would be allocated to Illinois Solar for All based upon the load and budget forecasts contained in Chapter 3 for the Illinois Solar for All program years covered by this Revised Plan – namely, 2022-2023 and 2023-2024.

Table 8-2: Utility Funding

Delivery Year	Utility Renewable Energy Maximum Budgets	5% of Funds	Allocation to Illinois Solar for All
2022-2023	\$224,170,249	\$11,208,512	\$11,208,512
2023-2024	\$225,207,712	\$11,260,385	\$11,260,385

These funds are supplied by each utility based on the allocation percentages contained in Section 3.1. These funds are not subject to the statutory percentage allocations for the funding from the RERF, specified in Section 1-56(b)(2). As discussed in Section 8.6.4, utility funding is not used for the Low-Income Community Solar Pilot Projects sub-program.

In this Revised Plan, the Agency proposes to continue the approach described in the Initial Plan that utility funding would be allocated to the three non-competitive sub-programs at a pro-rata level based on how the law allocates RERF funding to those three sub-programs (30% to the Low-Income Distributed Generation Initiative, 50% to the Low-Income Community Solar Project Initiative, and 20% to Incentives for Non-Profits and Public Facilities). As this allocation of utility funding to the sub-programs is not required by law, the Agency may adjust utility funding between those sub-programs on an as-needed basis during the program year if there are available funds in one sub-

⁵²⁹ 20 ILCS 3855/1-56(b-10).

program and higher demand in another sub-program, with the exception that funds for the Distributed Generation sub-program will not be reallocated.⁵³⁰

For each of the three non-competitively procured sub-programs, approved project applications within a program year will be first funded by the utility funds, and then by the RERF funds. The reason for this approach is that, starting with the 2021-2022 delivery year, utility funds are that not spent in a delivery year are returned to ratepayers through a reconciliation process,⁵³¹ while RERF funds are not subject to the same reconciliation and refund mechanism. Unallocated RERF funds within a sub-program from each program year would be rolled over to the following program year.

The funding for job training programs provided by ComEd (an electric utility that serves more than 3,000,000 retail customers) under Section 16-108.12 of the PUA is noted in the budget discussion in Chapter 3. As those funds are not directly part of the Illinois Solar for All Program as managed by the Agency, those funds are not included in this budget discussion. (The intersection between the Illinois Solar for All Program and the job training programs is discussed in Section 8.10.)

8.4.3. Section 16-108(k) Funding

Section 16-108(k) of the Public Utilities Act contemplates a possible situation in which the total amount of funds appropriated by the General Assembly from⁵³² the Renewable Energy Resources Fund during the period between June 1, 2017 and August 1, 2018 is less than \$200,000,000, creating a “funding shortfall.” This period encompassed part or all of three state Fiscal Years (running from July 1 of a given year to June 30 of the following year). Under this provision, if there was a funding shortfall, additional funding from the utilities could be available, as discussed below, and “may be used to fund the programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act in the same proportion the programs are funded under that subsection (b)” to provide additional support to Illinois Solar for All as part of a supplemental plan developed by the Agency.⁵³³

If this provision is interpreted to be based on the amounts appropriated for the whole of all three Fiscal Years covered (rather than a prorated amount of the appropriations for the first and last years, Fiscal Year 2017 and Fiscal Year 2019), then for each of the three fiscal years, the appropriation made totals \$150 million for the relevant period.⁵³⁴

The Agency notes that an appropriation is merely authority to spend funds up to the appropriated amount for the purposes contained in an applicable Fiscal Year’s appropriation bill. It may not correspond to the actual Fund balance or match actual expenditures made in that fiscal year.

In addition, this funding would only have been available if the funds collected from ratepayers by the utilities through their RPS riders exceeded their expenditure to fund their purchases of RECs under

⁵³⁰ See Section 8.6.1.1.

⁵³¹ See 220 ILCS 5/16-108(k).

⁵³² The sixth paragraph of Section 16-108(k) of the Public Utilities Act defines the “funding shortfall” based on amounts appropriated by the General Assembly *to* the Renewable Energy Resources Fund. However, the General Assembly has, in fact, never made an appropriation *to* the RERF. The General Assembly does, though, regularly make appropriations *from* the RERF. (See, e.g., Public Act 99-0524, enacted June 30, 2016, at Art. 24, § 10; Public Act 100-0021, enacted July 6, 2017, at Art. 45, § 10.) Thus, the IPA interprets the word “to” as a scrivener’s error, intended to mean “from.”

⁵³³ 220 ILCS 5/16-108(k).

⁵³⁴ See *id.*

the RPS during each of the 2017-2018, 2018-2019, and 2019-2020 delivery years, and half of each year's difference, if any, would be available to offset the shortfall.

If there had been a funding shortfall and there are utility RPS rider overcollections during the 2017-2018, 2018-2019, and/or 2019-2020 delivery years that, in aggregate, do not exceed the funding shortfall, then Section 1-56(b)(7) provides that,

If additional funding for the programs described in this subsection (b) is available under subsection (k) of Section 16-108 of the Public Utilities Act, then the Agency shall submit a procurement plan to the Commission no later than September 1, 2018, that proposes how the Agency will procure programs on behalf of the applicable utility. After notice and hearing, the Commission shall approve, or approve with modification, the plan no later than November 1, 2018.

The Agency developed and filed its Supplemental Funding Plan with the Commission on August 31, 2018.⁵³⁵ That Plan concluded as follows regarding whether to use any funding shortfall to provide additional funding for the Illinois Solar for All Program:

Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA's annual RRB allocation, the legally-required availability of RERF funds previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)'s requirement that the RERF "shall not be subject to sweeps, administrative charges, or chargebacks," and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.⁵³⁶

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457. The Supplemental Funding Plan did note, however, that the Agency would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF's balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.⁵³⁷ As discussed further in Section 2.2.5.3, no funding was leveraged for ILSFA using this statutory authority during the applicable years.

8.4.4. Setting Budgets

The Agency has developed the Illinois Solar for All Program under the assumption that the funds available for the 2022-2023 and 2023-2024 delivery years will be funds from the RERF and the utility-supplied funds identified in Section 8.4.2. Table 8-3 provides a summary of the Illinois Solar for All funding.

⁵³⁵ See <https://www.icc.illinois.gov/docket/files.aspx?no=18-1457&docId=276329>.

⁵³⁶ Final Illinois Solar for All Funding Shortfall Plan, dated November 26, 2018, at 30.

⁵³⁷ See id. at 31.

Table 8-3: Total Illinois Solar for All Budgets⁵³⁸

Funding Source	Low-Income Distributed Generation Incentive	Low-Income Community Solar Project Initiative	Incentives for Non-Profits and Public Facilities	Low-Income Community Solar Pilot Projects
2022-2023 Program Year				\$37,500,000 from RERF
RERF	\$4,950,000	\$8,250,000	\$3,300,000	
Utility	\$3,362,553	\$5,604,256	\$2,241,703	
Total (\$27,708,512 ⁵³⁹)	\$8,312,553	\$13,854,256	\$5,541,703	(\$20 million allocated to 2019 procurement, balance for a 2022 or 2023 procurement)
2023-2024 Program Year				
RERF	\$4,950,000	\$8,250,000	\$3,300,000	
Utility	\$3,78,115	\$5,630,193	\$2,252,077	
Total (\$27,760,384)	\$8,328,115	\$13,880,193	\$5,552,077	

8.4.5. Payment Structure

The Illinois Solar for All Program is structured so that the Agency “may pay for such renewable energy credits through an upfront payment per installed kilowatt of nameplate capacity paid once the device is interconnected at the distribution system level of the utility and is energized.”⁵⁴⁰ Section 6.14.5 describes the options for the capacity factor used in the Adjustable Block Program to convert kilowatt size of a project to the number of RECs the system would be expected to generate over 15 years. Those same options apply to Illinois Solar for All; the price paid will be expressed on a dollar per REC basis, and payments will be based upon the 15-year expected REC production of the system. For example, as described in that section, using the standard capacity factor would mean that for each kW of capacity for a fixed-mount system, approximately 21 RECs would be generated over 15 years.

Payments for Illinois Solar for All incentives take the form of upfront payments upon energization of systems, with the similar conditions as the Adjustable Block Program that a system must also be registered in GATS or M-RETS to verify that it will produce RECs. However, as discussed in Section 8.6.4, the Agency proposes a different payment structure for Low-Income Community Solar Pilot Projects.

REC delivery contracts are either with the Agency or an electric utility, depending on the funding source,⁵⁴¹ and include the assignment of RECs from each system for 15 years. RECs from these contracts are applied to the annual RPS goals of the utility to which the project is interconnected, but do not count toward each utility’s new photovoltaic project targets.⁵⁴² Projects that receive a contract

⁵³⁸ As noted above in Section 8.4.1, the RERF sub-program funding amounts are gross budgets before deduction of administrative costs. Additionally, there could be unused utility funds and/or RERF funds from the sub-program budgets for 2018-2019 through 2021-2022 that are rolled over to 2022-2023.

⁵³⁹ This annual total budget figure, and the one below for 2023-2024, are for the three non-competitive sub-programs.

⁵⁴⁰ 20 ILCS 3855/1-56(b)(3).

⁵⁴¹ See 20 ILCS 3855/1-56(b)(2). (“Contracts that will be paid with funds in the Illinois Power Agency Renewable Energy Resources Fund shall be executed by the Agency. Contracts that will be paid with funds collected by an electric utility shall be executed by the electric utility.”)

⁵⁴² See id.

through Illinois Solar for All are not eligible also to receive a contract through the Adjustable Block Program.⁵⁴³

Contracts with the Agency (that utilize funds from the RERF) are standard contracts that include required state contract provisions—such as terms, conditions, and attachments—including a clause stating that payment is subject to appropriation. Contracts with the utilities may have similarities, but vary given the different requirements applicable to each.⁵⁴⁴ Similar to what was discussed in Section 6.7 regarding contracts for the Adjustable Block Program, the Agency published standard REC delivery contracts (one for the Agency as counterparty and one for a utility as counterparty) for Illinois Solar for All in May 2019; following the approval of the First Revised Plan the Agency updated the Illinois Solar for All REC contract structure following the concepts included in Section 6.7, including updates to the payment withholding in lieu of collateral option as discussed in Section 6.14.6. This new contract is being implemented for the fourth program year, 2021-2022.

The Act is silent on how to allocate RECs from projects located in the service territories of municipal utilities, rural electric cooperatives, or Mt. Carmel Public Utility. The Agency does not apply RECs from those projects procured through contracts with the Agency using the RERF to the utility RPS goals, while any RECs procured through contracts with a utility are applied to the RPS goals of the contracting utility.⁵⁴⁵

8.5. Programs

Section 1-56(b)(2) outlines four sub-programs of the Illinois Solar for All Program:

1. Low-Income Distributed Generation Incentive
2. Low-Income Community Solar Project Initiative
3. Incentives for Non-Profits and Public Facilities
4. Low-Income Community Solar Pilot Projects

The first three of these sub-programs provide an incentive based on the price per REC from the Adjustable Block Program, with adjustments to that price as described below to account for the specific needs of the Illinois Solar for All Program. The fourth sub-program has been competitively procured based on the competitive procurement approach discussed in Chapter 5, and further below in Section 8.6.4.

In addition to those four components, a provision of the Act allows stakeholders to propose alternative programs,

“In the course of the Commission proceeding initiated to review and approve the plan, including the Illinois Solar for All Program proposed by the Agency, a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed by the Agency, and the Commission may approve an additional

⁵⁴³ Section 1-56(b)(3) of the IPA Act requires that for Illinois Solar for All contracts, “[t]he payment shall be in exchange for an assignment of all renewable energy credits generated by the system during the first 15 years of operation.” Sections 1-75(c)(1)(L)(ii) and (iii) both contain provisions related to the various components of the Adjustable Block Program that, “[t]he electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation.” These two provisions from Section 1-56(b)(3) and Section 1-75(c)(1)(L) are mutually exclusive as only one REC can be produced, transferred, and retired for each MWh of generation.

⁵⁴⁴ See Docket No. 17-0838, Final Order dated April 3, 2018 at 151-152.

⁵⁴⁵ To date no approved Illinois Solar for All projects are located in the service territories of rural electrical cooperatives or municipal utilities.

program, or modifications to the Agency's proposed program, if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed."⁵⁴⁶

Based on experience and best practices in other states and jurisdictions, the Agency has proposed program elements in Section 8.7 intended to increase the success of low-income solar deployment in Illinois. Those elements are intended to go beyond providing financial incentives to include providing guidance on project development for low-income customers, non-profits, and public sector customers. Additionally, the Agency will continue to monitor the treatment of multi-family buildings under the Low-Income Distributed Generation Incentive sub-program.⁵⁴⁷

Any changes (compared to the First Revised Plan) to sub-program terms and conditions, and other general aspects of Illinois Solar for All, described subsequently in this Chapter (as well as the budgetary discussion in Section 8.40 above) will be effective for the 2022-2023 and 2023-2024 program years and will not apply to the 2021-2022 program year which will still be underway at the time the Agency expects this Revised Plan to be approved by the Commission.

As listed in Table 8-3, approximately \$27.7 million is expected to be available in program year 2022-2023 and \$27.8 million in program year 2023-2024 for the non-competitively procured sub-programs. The utility-supplied funding will not be available for the Low-Income Community Solar Pilot Projects,⁵⁴⁸ and the percentage funding allocations only apply to the funds from the Renewable Energy Resources Fund. The Agency proposes that the utility-supplied funding will be evenly allocated to the other three programs at the same relative weightings, but will monitor activity and may shift the use of the utility funding between sub-programs as needed.

8.6. Setting Incentive Levels

The incentive levels described in the following Sections were derived by utilizing the REC prices for the Adjustable Block Program as described in Section 6.4 and adjusting those prices to meet the objectives of the Illinois Solar for All Program. These incentives will be offered through a 15-year REC delivery contract, either with the Agency for projects funded with the Renewable Energy Resources Fund, or with a utility for projects funded through utility-supplied funds.

Incentive levels are expressed as REC prices, and are set according to the same groups and categories as the Adjustable Block Program (Group A for projects located in Ameren Illinois, Mt. Carmel, MidAmerican, and rural electric cooperatives and municipal utilities located in MISO; Group B for projects located in ComEd, and rural electric cooperatives and municipal utilities located in PJM). Unlike the Adjustable Block Program, these incentives have not been and will not be adjusted upward or downward based upon blocks of capacity filling. Rather, the Agency proposes to review and update the incentive levels on an annual program year basis. That update will include an adjustment to account for how the comparable Adjustable Block Program REC price for each Group and category has changed since the previous update, allowing for the prices offered through Illinois Solar for All to

⁵⁴⁶ 20 ILCS 3855/1-56(b)(4).

⁵⁴⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 153.

⁵⁴⁸ See Section 8.6.4 for a discussion of funding sources for the Low-Income Community Solar Pilot Projects.

track overall market conditions while continuing to be offered at a higher level than for the Adjustable Block Program.

For this draft Second Revised Plan, the Agency is proposing an update to ILSFA REC Prices based on the preliminary modeling of the updated REC Pricing Model described in Chapter 6 and in Appendices D and E. The Agency wishes to emphasize that these updated prices are preliminary in nature and the Agency requests that stakeholders provide feedback on the updated REC prices during the comment period for the Agency to consider prior to the Agency filing the Second Revised Plan for Commission approval. The changes to REC Prices largely reflect changes to the underlying modeling used for the Adjustable Block Program that then flow through to Illinois Solar for All.

In setting REC prices for the Low-Income Distributed Generation Incentive sub-program for the Initial Plan, the Agency adjusted the Adjustable Block Program's REC prices in the CREST model by setting the assumed debt financing of the project to 0%, and increasing the net metering benefit shared with participants from 20% to (i) 100% for residential participants in 1-4 unit buildings, and (ii) 50% for residential participants in larger buildings.⁵⁴⁹ For this draft Second Revised Plan the Agency proposes increasing the development costs component of the model for 1-4 unit buildings to 150% of the value used in the Adjustable Block Program to recognize the increased complexity of developing residential projects as part of Illinois Solar for All.

For the Low-Income Community Solar sub-program, the Adjustable Block Program REC prices were adjusted by shortening the financing term to five years and lowering the debt financing to 35%. For the Incentives for Non-Profits and Public Facilities sub-program, REC prices were adjusted from the ABP DG pricing model by considering the project as a non-taxable entity; the up-to-10 kW size segment was assumed to be non-residential instead of residential; and the net metering benefit to be shared with participants was increased from 20% to 50%. The Agency does not propose any adjustments to the REC prices for these two sub-programs for this Second Revised Plan.

The Agency believes these approaches represent reasonable proxies for the higher incentive level needed for Illinois Solar for All projects to overcome the financing barriers and other hurdles these project face.

8.6.1. Low-Income Distributed Generation Incentive

The Low-Income Distributed Generation Incentive sub-program is intended to provide funding for photovoltaic projects located on individual homes and multi-unit residential buildings. In addition to the requirements of the Adjustable Block Program, qualifying projects will be subject to the additional low-income consumer protections outlined in Section 8.14. As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities. In approving and modifying the First Revised Plan, the Commission noted that multi-faceted challenges to participation in this sub-program must be addressed. The Agency has worked with stakeholders to develop improvements to this sub-program.⁵⁵⁰ The Agency notes that although participation in the Low-Income Distributed Generation sub-program has increased, the majority of funds in the sub-program remained unspent at the end of each program year. The Agency and

⁵⁴⁹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 155; see also Appendices E-3-a and E-3-b.

⁵⁵⁰ See Docket No. 19-0995, Final Order dated February 18, 2020 at 101.

Program Administrator have worked to identify barriers to participation in this sub-program and made adjustments to increase participation, lower soft costs, and simplify sales procedures.

A referral process was developed in fall of 2020 and stakeholder input was received through the end of the year.⁵⁵¹ The referral process and an income verification process for single-family homeowners were both implemented in mid-2021. For this draft Second Revised Plan, the Agency clarifies that it interprets the Commission's directive to implement such processes in a competitively neutral fashion to mean implementation in such a manner that it does not give advantage to one Approved Vendor or group of Approved Vendors over others, nor does it give the appearance of doing so. Furthermore, the referral process should consider geography, availability of Approved Vendors serving single-family customers in a potential participant's area, services provided, the efficiency of the process, and providing the best offers to participants in a transparent manner.

Additional proposals for streamlining the sales process have been made for this draft Second Revised Plan including:

- Extending the time period in which the Program Administrator-provided income verification is valid from 6 to 12 months (Section 8.13.2)
- Amending Section 8.13 to eliminate the requirement to present and sign the disclosure three days prior to consummation of the contract along with an extension of the cancellation period to simplify the customer engagement process with one less touchpoint in the customer acquisition process; and
- The proposal of a pilot project to more closely work with third-party energy efficiency program administrator or Community Action Agencies to facilitate connecting their participants to Approved Vendors and providing initial site suitability screening where applicable (Section 8.15).

Although the Agency is hopeful that these changes will help to lower soft costs and encourage increased participation in the sub-program, it is noteworthy that one of the specific barriers identified to increasing participation is the complexity of the sub-program and confusion or mistrust from potential participants. **In an effort to address this particular issue, the Agency is proposing that messaging be streamlined to improve trust in the program by providing Approved Vendors the option of shifting some of the customer acquisition and income verification efforts to the Program Administrator conditional upon the Approved Vendor providing a 100% savings offer (i.e., no cost to the participant) for 1-4 unit projects. Approved Vendors who wish to participate in the Low-Income Distributed Generation referral process or to submit a project that uses the Program Administrator's Income Verification must offer participants 100% savings for their systems. The Agency notes that several Approved Vendors have currently provide standard offers at no cost to participants. Standardizing the cost to participants will allow for the Program Administrator to more clearly describe active offers through the referral program and minimize confusion and the mistrust that comes with having additional solar bills. Approved Vendors would still be able participate in the Low-Income Distributed Generation sub-program with offers that have less than 100% savings (provided at least 50% of the value produced by the solar system through avoided usage or**

⁵⁵¹ In response to concerns raised by various stakeholders in the process of approving the First Revised Plan, the Commission determined that the Agency and the Program Administrator shall explore implementing a process to connect interested income-qualified customers with ILSFA Approved Vendors, and that the Agency must implement any such process in a competitively neutral fashion. (Docket No. 19-0995, Final Order dated February 18, 2020 at 108.) This referral program implements that directive.

net metering credits still flows through to the participant), but Approved Vendors with those sub-100% offers would not be eligible to participate in the Program Administrator run referral program or streamlined income verification process. The Agency welcomes stakeholder feedback on these proposed refinements and what other proposals could be considered.

8.6.1.1. Eligibility

The Agency proposes to continue to treat residential buildings with one to four units differently than residential buildings with five units or more. For single-family homes, households must verify that they are low-income; for two- to four-unit residential buildings, at least two of the households must be verified as low-income. For five-unit and larger residential buildings, either at least 50% of the tenants must be verified as low-income, or the building must be demonstrated to meet the definition of “affordable housing” contained in the Illinois Affordable Housing Act.⁵⁵² In addition to projects being eligible based on household income, projects developed on homes or buildings that qualify for US Department of Housing and Urban Development (“HUD”) Project-Based Vouchers or Project-Based Rental Assistance (which are programs for housing units dedicated to low-income tenants) also qualify. The income qualification levels required for participation in these programs are lower than income requirements for the Illinois Solar for All program.

The project selection protocol⁵⁵³ developed by the Program Administrator scores projects in a manner that will help to ensure a diversity of projects between 1-4 unit buildings and multi-family buildings. To further ensure that diversity of projects, 25% of the program year budget will be reserved for 1-4 unit building projects. At the end of each program year, unused funds in this reserved sub-category will rollover to unreserved funds for the following program year of Distributed Generation sub-program, in accordance with the Commission’s order in approving and modifying this Revised Plan.⁵⁵⁴

8.6.1.2. Demonstrating Tangible Economic Benefits for Residents of Multi-family Buildings

Section 1-56(b)(2) requires that the Illinois Solar For All incentives deliver tangible economic benefits for eligible low-income customers, including those that live in multi-family buildings. Multi-family buildings can be either master metered or individually metered. For master-metered buildings, the economic benefits of installing a photovoltaic system will not directly impact the occupants of the building because they do not individually pay an electric bill to their electric utility; but instead the benefits accrue to the building owner/manager. **For this draft Second Revised Plan, the Agency proposes to clarify that for master-metered building owners to be eligible for the Low-Income Distributed Generation Incentive sub-program, the building owner/manager will need to commit to passing along the value of at least 50% of the energy savings from net metering to tenants in tangible ways: reduced (or not raised) rents; new staff that serves all tenants; facility upgrades; new equipment that serves all tenants; or other payments, benefits,**

⁵⁵² See Section 8.13.1 for more information on income verification and Section 8.13.2 for more information on income eligibility (including a required commitment for owners of multi-family buildings).

⁵⁵³ See: <https://www.illinoisfsfa.com/app/uploads/2019/05/ILSFA-Project-Selection-Protocol.pdf> for the 2018-2019 and 2019-2020 program year protocol. As stated in Section 8.6.2, an updated project selection protocol will be developed for program years 2020-2021 and 2021-2022.

⁵⁵⁴ See Docket No. 19-0995, Final Order dated February 18, 2020 at 100-101.

or services to all tenants that would not otherwise have been possible without the savings generated by the photovoltaic system. These benefits must be made available to all the tenants, regardless of income level or individual participant uptake. Additionally, the building owner/manager will communicate to all residents those benefits and how they resulted from the installation of solar. The building owner/manager shall demonstrate the commitment to pass along the full value of the required savings to residents by describing in detail how this will be accomplished. The Agency welcomes stakeholder feedback on this clarification.

One challenge to multi-family buildings that are not master-metered is that the photovoltaic system will most likely be connected to the main building account that serves common areas and building-wide load rather than to any individual unit’s account. For these buildings, the owner/manager must either provide the same demonstration of passing along benefits to all tenants as for master-metered buildings or, in the alternative, must make available to all tenants the opportunity (at no additional upfront cost levied by the landlord) to participate in net metering pursuant to the provisions of Section 16-107.5(l)(1)(B) of the PUA, which allows for net metering of “individual units, apartments, or properties located in a single building that are owned or leased by multiple customers and collectively served by a common eligible renewable electrical generating facility.” In this instance, the project will utilize the interconnecting utility’s applicable net metering tariff, which will require the Approved Vendor to maintain system shares for all participating tenants/meters. The net metering bill credit in this instance will be supply-only and costs/savings will be based off of this net metering value.

8.6.1.3. Incentive Level

As discussed in Section 8.6, these REC prices are based on an update of the REC Pricing model developed for this draft Second Revised Plan and the Agency welcomes stakeholder feedback on this preliminary analysis.

Table 8-4: Incentives for the Low-Income Distributed Generation Program, 1-4 unit buildings (\$/REC)

System Size	Group A	Group A Change from Initial and First Revised Plan Prices	Group B	Group B Change from Initial and First Revised Plan Prices
≤10 kW	\$161.86	113%	\$177.53	124%
>10 - 25 kW	\$144.11	113%	\$159.97	125%
>25 - 100 kW	\$113.70	110%	\$124.91	121%
>100 - 200 kW	\$97.67	108%	\$104.23	115%
>200 - 500 kW	\$90.75	108%	\$95.99	114%
>500 - 2,000 kW	\$89.41	111%	\$86.43	107%

Table 8-5: Incentives for the Low-Income Distributed Generation Program, 5+ unit buildings (\$/REC)

System Size	Group A	Group A Change from Initial and First Revised Plan Prices	Group B	Group B Change from Initial and First Revised Plan Prices
≤10 kW	\$118.10	100%	\$124.45	105%
>10 - 25 kW	\$107.74	101%	\$118.72	110%
>25 - 100 kW	\$87.16	99%	\$98.37	111%
>100 - 200 kW	\$73.91	99%	\$80.99	108%
>200 - 500 kW	\$67.61	99%	\$73.57	106%
>500 – 2,000 kW	\$66.22	101%	\$64.37	98%

These incentive payments are intended to be sufficient to provide tangible economic benefits to participants through enabling project developers to eliminate upfront costs to the participants for the installation of photovoltaic projects. The REC price is a standard incentive for the contractually obligated delivery of a renewable energy credit and not customized for each project.

Projects that participate in this incentive will also be subject to the provisions related to job training discussed in Section 8.9.

8.6.2. Low-Income Community Solar Project Initiative

This sub-program, or initiative, is intended to support participation in community solar by low-income subscribers. To qualify for this initiative, community solar projects must meet conditions beyond the requirements for community renewable generation projects outlined in the Act and beyond those applicable community solar projects that participate in the Adjustable Block Program. These include:

- *“Each project shall identify its partnership with community stakeholders regarding the location, development, and participation in the project, provided that nothing shall preclude a project from including an anchor tenant that does not qualify as low-income.”*
- *“Incentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit organizations, and affordable housing owners.”⁵⁵⁵*

For the first provision, ILSFA Approved Vendors’ project applications must include a description of a partnership with community stakeholders in the community where the project will be located applicable to that project. While the Act does not define the term “community stakeholders,” the National Community-Based Organization Network (NCBON) defines a community-based organization as one in which:

- The majority of the governing body and staff consists of local residents,

⁵⁵⁵ 20 ILCS 3855/1-56(b)(2)(B).

- The main operating offices are in the community,
- Priority issue areas are identified and defined by residents,
- Solutions to address priority issues are developed with residents, and
- Program design, implementation, and evaluation components have residents intimately involved, in leadership positions.⁵⁵⁶

The Agency will consider entities that demonstrate that they meet this definition as being able to represent community stakeholders in a partnership. Furthermore, the Agency believes the intent of the Act was to create substantial partnerships, going beyond just holding a few community meetings. In addition to information regarding location, development and participation, these partnerships should include a description of how the partnership shows that it is responsive to the priorities and concerns of low-income members of the community.

In its Initial Plan, the Agency proposed that a public entity may qualify as a community-based organization for this purpose, but only if the public entity meets the following requirements:

- The public entity must represent a municipality or county (or school district, park district, etc.) in a municipality or county in the bottom 25% of the state by population.
- The public entity must certify that no local community-based organizations exist that are capable of filling this role.
- The public entity must provide the same showing of robust community engagement as a non-public entity would be required to show.
- Public entities that have failed to act as community-based partners in a past project certification would be ineligible.

The public entity would be qualified as a “community-based organization” only in the context of one project application; the qualification would not be retained for a future project application (the public entity would need to demonstrate the same factors again). Finally, the public entity must provide ongoing reporting of its engagement approach, including public participation opportunities and disclosure of its approach to the project location selection (if applicable).

If the proposed project has an anchor tenant that does not qualify as a low-income residential household, the application shall describe that anchor tenant in detail; the Illinois Solar for All incentive will be reduced to account for the share of the system subscribed by that tenant not receiving a low-income incentive. As approved in the First Revised Plan, for any anchor tenant, that reduction is achieved by pricing the non-low-income anchor tenant share at the equivalent applicable Adjustable Block Program REC price (non-profit or public anchor tenants no longer qualify for the higher ILSFA price). A project may only have one anchor tenant, and that anchor tenant must be identified at the time of application.

In order to encourage projects that have deep community connections, the project selection protocol (see Section 8.12.2) reflects the following prioritization in project selection:

- Projects for which the anchor tenant is a non-profit or public facility critical service provider and also the project host;

⁵⁵⁶ National Community-Based Organization Network (NCBON), “What is a Community-Based Organization (CBO)?” <https://sph.umich.edu/ncbon/about/whatis.html>.

- Projects for which the anchor tenant is a non-profit or public facility that is not a critical service provider and is also the project host;
- Projects for which the anchor tenant is a non-profit or public facility critical service provider but not the project host;
- Projects for which the anchor tenant is a non-profit or public facility that is not a critical service provider but not the project host;
- Projects for which the anchor tenant is not a non-profit or public facility.

To qualify for any preference in project selection for a project with an anchor tenant, the anchor tenant subscription must be at least 10% of the project size (and, by law, may not be more than 40%).

Regarding projects “that are 100% low-income subscriber owned,” the Agency assumes the Act intended the plain meaning of the word “ownership,” and not that projects be merely 100% “subscribed” by low-income customers. For projects that can demonstrate that they are 100% owned by low-income subscribers (including not-for-profit organizations, and affordable housing owners), the incentive level will be increased by \$5/REC. To be eligible for this additional incentive, the Illinois Solar for All Approved Vendor will need to certify the intent for the project to be 100% low-income subscriber owned at the time of application, and if the project is not initially structured this way, the applicant will have up to six years after energization to complete the full transfer of ownership to the low-income subscribers. The price of the transfer must be provided at the time of application and will be subject to approval by the Agency. The application must also contain a commitment that the project remain 100% low-income subscriber owned after the transfer. The additional incentive will be paid only upon the Illinois Solar for All Approved Vendor providing documentation to the Agency that the project is 100% low-income subscriber owned. The Agency understands that 100% low-income subscriber owned projects may face challenges in arranging financing. However, as the Act clearly states “100% low-income subscriber owned,” the Agency is not able to offer flexibility to allow other ownership models for this provision.

As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities.

8.6.2.1. Incentive Level

As discussed in Section 8.6, these REC prices are based on an update of the REC Pricing model developed for this draft Second Revised Plan and the Agency welcomes stakeholder feedback on this preliminary analysis.

Table 8-6: Incentives for Low-Income Community Solar Projects (\$/REC)

System Size	Group A	Group A Change from Initial and First Revised Plan Prices	Group B	Group B Change from Initial and First Revised Plan Prices
≤10 kW	\$131.81	108%	\$143.89	120%
>10 - 25 kW	\$121.48	108%	\$134.60	123%
>25 - 100 kW	\$101.76	109%	\$110.99	122%
>100 - 200 kW	\$90.23	112%	\$94.72	121%
>200 - 500 kW	\$84.77	113%	\$88.57	123%
>500 - 2,000 kW	\$55.88	78%	\$63.35	92%
Co-located systems exceeding 2 MW in aggregate size	\$52.92	82%	\$61.38	99%

These incentives for Low-Income Community Solar Projects are for the portion of the project subscribed by subscribers who have been verified as low-income. In order to receive the incentive at the time of energization, the Approved Vendor will have to verify the level of low-income subscribers to the Project as outlined in Section 8.13.1. The Agency notes that the Adjustable Block Program only requires 50% of subscribers (in kW volume) to be identified at the time of energization, and that small subscriber adders are granted only if the project meets the small subscriber level after one year of operation. This principle applies to Solar for All’s Low-Income Community Solar Project Initiative as well. Only 50% of the low-income subscribers will need to be identified by the time the project is energized to receive payment under the REC delivery contract; however, the total amount of that incentive payment will be prorated to the anchor and low-income subscription levels at the time of energization. After one year, a payment adjustment shall potentially be made based upon the anchor and low-income subscription level achieved by that time.

To ensure ongoing subscription levels by low-income subscribers, the Approved Vendor will have to provide ongoing collateral for ten years equal to 5% of the remaining REC value and report annually on low-income subscription levels. If those levels are not maintained, then the collateral may be called upon to claw back the incentives to the level of low-income subscription.

Additionally, the “adders” for small subscriber participation, as defined and described in Section 6.5.3 above relating to community solar projects in the Adjustable Block Program, will also apply to the REC prices for participating projects in the Low-Income Community Solar Project Initiative sub-program.⁵⁵⁷ Only residential low-income subscribers with subscription sizes below 25 kW will count as “small subscribers” for this purpose.

⁵⁵⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 155.

8.6.3. Incentives for Non-Profits and Public Facilities

Section 1-56(b)(2)(C) of the Act specifies that “non-profits and public facilities” are eligible to receive incentives for on-site photovoltaic generation. These incentives are designed to “support on-site photovoltaic distributed renewable energy generation devices to serve the load associated with not-for-profit customers and to support photovoltaic distributed renewable energy generation that uses photovoltaic technology to serve the load associated with public sector customers taking service at public buildings.”⁵⁵⁸ The Act does not specify what specific non-profit organizations or public sector customers may be eligible.

Given that the objective of the Illinois Solar for All Program is in part “to bring photovoltaics to low-income communities,”⁵⁵⁹ it is reasonable to infer that only non-profits and public sector customers that in some manner serve low-income communities should be eligible. However, the Act could also be interpreted such that all non-profits and public facilities would be eligible to participate; this interpretation would be consistent with the General Assembly’s findings that “the State should encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois’ energy resource mix, and protect the Illinois environment,”⁵⁶⁰ which could involve a wider range of photovoltaic facilities that would be eligible for these incentives. Because current funding levels are such that only a few large projects might make up the whole of the Non-Profit/Public Facilities budget in a single program year, focusing available funds on low-income and environmental justice communities to align with the implied legislative objectives has been the Agency’s approach.

To balance these objectives, initially Illinois Solar for All Approved Vendors will have to demonstrate that the project:

1. Documents that it meets the standards described in Section 8.11 related to projects having sufficient connection to, and input from, low-income community members;
2. Is sited within an environmental justice community⁵⁶¹ or low-income community;⁵⁶²
3. Serves the electricity load of a building that is occupied by an organization that is a critical service provider for the community⁵⁶³ (e.g., youth centers, hospitals, schools, homeless shelters, senior centers, community centers, places of worship, affordable housing providers including public housing sites); if a public facility, the building must host a department/agency that is a critical service provider meeting this standard; and
4. The Approved Vendor must either certify that the project’s owner will not apply for the federal Investment Tax Credit in relation to the project installation, or if it will apply for the Investment Tax Credit, then the savings level for the participating host of the project must be 65% of energy value rather than 50%.

⁵⁵⁸ 20 ILCS 3855/1-56(b)(2)(C).

⁵⁵⁹ 20 ILCS 3855/1-56(b)(2).

⁵⁶⁰ Public Act 99-0906, Section 1(a)(1) (“Findings”).

⁵⁶¹ As defined by the methodology outlined in Section 8.15.2 of this Revised Plan.

⁵⁶² A “low-income community” for this purpose is defined as a census tract where at least half of households are not exceeding 80% of AMI.

⁵⁶³ If the building is not owned by the organization or public agency, then either a lease with at least five years remaining on it, or a commitment by the building owner to lease the facility to a critical service provider for at least five years must be provided.

As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities.

8.6.3.1. Incentive Level

As discussed in Section 8.6, these REC prices are based on an update of the REC Pricing model developed for this draft Second Revised Plan and the Agency welcomes stakeholder feedback on this preliminary analysis.

Table 8-7: Incentives for Non-Profits and Public Facilities (\$/REC)

System Size	Group A	Group A Change from Initial and First Revised Plan Prices	Group B	Group B Change from Initial and First Revised Plan Prices
≤10 kW	\$144.77	93%	\$153.14	98%
>10 - 25 kW	\$135.76	95%	\$149.96	105%
>25 - 100 kW	\$114.75	97%	\$129.22	108%
>100 - 200 kW	\$99.30	97%	\$108.22	105%
>200 - 500 kW	\$91.83	96%	\$99.47	103%
>500 - 2,000 kW	\$90.52	99%	87.86	95%

8.6.4. Low-Income Community Solar Pilot Projects

Low-Income Community Solar Pilot Projects will participate in the Illinois Solar for All Program in a manner that is different from projects that participate in the other portions of the Program.

Unlike those other programs, the Low-Income Community Solar Pilot Projects “shall be competitively bid by the Agency, subject to fair and equitable guidelines developed by the Agency.”⁵⁶⁴ This means that rather than applying to the Illinois Solar for All Program and receiving an administratively determined REC price, the incentive will be determined through a competitive bidding process as outlined in Chapter 5. The Agency has a well-established process for competitive procurements, and for this process, the Agency will leverage that experience.

In addition to the general provisions that the Agency uses for competitive procurements (e.g. sealed, pay-as-bid request for proposal process), the Agency also recommends that certain provisions related to other community solar projects also apply to the pilot projects: including the eighteen-month window of time for project development, and project and customer information requirements.

The procurement for Low-Income Community Solar Pilot Projects will be bid on a \$/REC basis, for contracts for 15 years of delivery of all RECs from the project to the Agency once the project is energized. The price paid will be based solely on the bid price and will not include any payment based on the Adjustable Block Program REC prices (or adders/adjustments). For this Revised Plan, the

⁵⁶⁴ 20 ILCS 3855/1-56(b)(2)(D).

Agency proposes that payments for projects contracted through this sub-program via the second Pilot Projects procurement, to be held in 2020-2021 or 2021-2022, will be made over the 15 years of REC deliveries (rather than the first 10 years as provided in the Initial Plan for the first Pilot Projects procurement). To ensure that the procurement follows “fair and equitable guidelines,” the Agency proposes that bids be evaluated only on the basis of price, as this is the most objective way to consider bid evaluation. While the Low-Income Community Solar Pilot Project procurement process requires additional considerations (described below), the Agency believes that those considerations are better applied as minimum criteria for determining eligibility to participate in the procurement rather than applied to the evaluation of competing bids (with the limited example provided below for why bids could be considered out of price order).

There are several considerations under Section 1-56(b)(2)(D) of the Act for how the competitive procurement is conducted that must be specifically considered and adapted for the Low-Income Community Solar Pilot Projects competitive procurement.

First, the Agency notes that the total funding over time for Low-Income Community Solar Pilot Projects cannot exceed \$50,000,000, and that it cannot exceed \$20,000,000 per project. However, as discussed in Section 8.4.1, only a maximum of \$37.5 million is available from the RERF for this sub-program. Furthermore, projects are allowed to be larger than the 2,000 kW limit that otherwise applies for community renewable generation projects under net metering laws and tariffs.

Second, projects “must result in economic benefits for the members of the community in which the project will be located.” The Agency believes that this provision can be met by requiring projects that wish to bid in the procurement adhere to the same provisions as the Low-Income Community Solar Projects in terms of partnerships with community stakeholders. Projects must also provide information about how they will comply with this provision through options such as providing commitments to local hiring and use of M/WBE contractors, describing impact on payments to community residents or community-based organizations as part of the project development process, and offering of subscriptions to community residents and community-based organizations (which will have to meet the same 50% savings requirement as the other Low-Income Community Solar sub-program). Failure to meet commitments made during the bidder/project registration phase of the procurement will be considered actions that would result in a default and cancellation of the contract.

Third, projects “must include a partnership with at least one community-based organization.” Information on the partnership will be required to register during the initial bidder registration phase and projects that cannot demonstrate such a partnership will not be eligible to bid. As described in Section 8.6.2, the community-based organization(s) should be an existing non-profit (or in limited circumstances a government agency) organization that provides programs and services within the same defined community as where the proposed project will be located.

Fourth, funds “may not be distributed solely to a utility;” and fifth, “at least some funds under this subparagraph (D) must include a project partnership that includes community ownership by the project subscribers.” These two provisions create interesting challenges in the evaluation of bids. For example, if bids are received and only the highest priced bid includes “a project partnership that includes community ownership,” (a distinct requirement around ownership that goes beyond the requirement that applies to all projects that they have a partnership with a community-based organization) but constitutes the only project able to be supported under the available budget, it

would have to be selected. Similarly, to ensure that funds are not distributed solely to utilities, bids may need to be selected out of price order, otherwise, only a utility project would win.

Because utilities are potentially bidders in this procurement, contracts resulting from this procurement may only be entered into by the Agency and only use the Renewable Energy Resources Fund as a source of contract funding. While generally the Illinois Solar for All Program allows for contracts to be entered into either with the Agency (using the RERF) or with one of the utilities, it would be inappropriate for utilities potentially to enter into contracts with themselves, and furthermore, the procurement process could allow for them as the Buyer to receive confidential information from competing bidders (e.g., potential Sellers).

The Agency conducted a procurement for Low-Income Community Solar Pilot Projects in late 2019 with a budget of \$20 million (which will cover the 15-year REC contract value of selected projects).

In the First Revised Plan, the Agency proposed conducting a second procurement during either the 2020-2021 or 2021-2022 program years for the balance of remaining funds for the Low-Income Community Solar Pilot Projects sub-program. The Agency sought stakeholder feedback on the procurement design in May of 2021. At the same time, it appeared that legislative proposals to update the RPS would reallocate the remaining funding for this sub-program to other parts of Illinois Solar for All; as a result the Agency held back from moving forward with this next procurement. Assuming that legislation does not reallocate the available funding for this sub-program, the Agency in this draft Second Revised Plan proposes to hold a procurement with that remaining funding during the 2022-2023 program year. Prior to conducting the procurement, the Agency will seek additional stakeholder feedback to explore possible innovations for this next procurement.

8.7. Providing Guidance and Education

The Illinois Solar For All Program provides substantial financial incentives intended to enable low-income, non-profit, and public sector customers to share in the benefits of solar power. These customers are specifically identified in the legislation partly because they face additional hurdles in deploying solar, such as a lack of taxable income needed to monetize tax-based incentives, a lack of access to capital, or institutional barriers that limit deployment.

At the same time, such customers have access to a wide variety of non-energy programs and policies intended to promote economic development, provide affordable housing, and reduce the burdens of poverty. Programs from the U.S. Department of Housing and Urban Development, for example, provide financial assistance for housing and utility bills. Such programs are supporting solar deployment to reduce utility expenses for both residents and taxpayers.

Experience in other states has shown that there are many finance-related and other policies and programs at the federal, state, and local level that can be applied to low-income solar development. The Agency believes that the Illinois Solar For All Program would benefit from guidance and education provided to Illinois Solar for All Approved Vendors, community groups, public-sector customers, and others, in addition to the financial incentives described in other sections of the Plan. One vehicle for providing such guidance is the Program Administrator(s) that manages the Illinois Solar For All Program.

8.8. Illinois Solar for All Program Administrator

The Program Administrator for the Illinois Solar for All Program was selected via a two-part Request for Qualifications/Request for Proposals process conducted by the Agency in 2018, which culminated in Commission approval of the contract for Elevate Energy to serve as the ILSFA Program Administrator on September 14, 2018.

The Illinois Solar for All Program Administrator(s) will at minimum:

- Take applications and verify project eligibility in Illinois Solar for All and coordinate this information with the Adjustable Block Program Administrator (who will process the actual generation of contracts). This includes, but is not limited to, review of project technical specifications, income verification, review of community involvement in projects, review of job training coordination, and review of Illinois Solar for All consumer protections such as verification of ensuring tangible economic benefits flow to low income participants.
- Act as the centralized source for income verification and maintain database of program participants.
- Assist in the development of contracts, disclosure forms, and brochures for use by Illinois Solar for All Approved Vendors and their partner community-based organizations.
- Coordinate the distribution of funding for grassroots education efforts by community-based organizations. A priority for this funding will be to promote the availability of the Illinois Solar for All Program in Environmental Justice Communities to achieve the goal of 25% of the incentives being allocated to those communities.
- Facilitate Illinois Solar for All Approved Vendors meeting the additional requirements of the Illinois Solar for All Program. In particular, the Program Administrator acts as a liaison between Illinois Solar for All Approved Vendors participating in the programs and organizations providing job training. The Program Administrator shall also work to inform Illinois Solar for All Approved Vendors of energy efficiency, weatherization, lead abatement, and other program opportunities that could provide additional benefits to participants.
- Provide guidance and education to Illinois Solar for All Approved Vendors, community groups, local government agencies, and others on how to leverage other governmental policies to facilitate low-income solar projects and energy efficiency programs. Other relevant policies include affordable housing, economic development, public finance, and tax policies, at the federal, state, and local level. The Administrator will act as liaison with other governmental agencies that administer such programs to facilitate their use on solar development.
- Provide Program Manual and related materials for use by Illinois Solar for All Approved Vendors.
- Provide reports to the Agency and the Commission on a quarterly basis on the status of the Program including, but not limited to, number of applications received, number of

applications approved, number of projects completed, REC payments, payments for and status of grassroots education efforts (if applicable), and a summary of technical assistance provided.

8.9. Quality Assurance

Due to the higher incentive level that Illinois Solar for All projects will receive compared to those that participate in the Adjustable Block Program, as well as the additional vulnerabilities that program participants may face, it is especially important for the Agency to ensure that projects are properly installed and produce their expected amounts of energy. In conjunction with the Program Evaluator (as described in Section 8.17), the Illinois Solar for All Program Administrator has developed and implemented a process for quality assurance, including assessing 1) the suitability of sites for solar installation and/or the proper planning for mitigating site deficiencies before installation, 2) a thorough photo documentation of all projects while under construction, and 3) on-site inspection of a random sample of installations. If installations are found to have deficiencies or nonconformance with specifications from the application, the Illinois Solar for All Approved Vendor, at its own expense, will be responsible for any repairs, alterations, or additions to remedy the deficiencies. A deficient project may be removed from the Program if already contracted. Illinois Solar for All Approved Vendors who have a disproportionately high number of deficient systems may lose their eligibility to continue to participate in the Illinois Solar for All Program.

8.10. Coordination with Job Training Programs

Section 1-56(b)(2) of the Act contains two provisions that are designed to ensure that the job trainees supported by the ComEd job training programs⁵⁶⁵ established under Section 16-108.12 of the Public Utilities Act participate in the installation of photovoltaic projects supported by the program. The first of these requirements is aspirational in nature, while the second is more specific.

The first provision is that “[p]rojects must include job training opportunities if available, and shall endeavor to coordinate with the job training programs described in paragraph (1) of subsection (a) of Section 16-108.12 of the Public Utilities Act.”⁵⁶⁶ This program is known as the “solar training pipeline program.” Under this provision, ComEd is to spend \$3,000,000 in each of 2017, 2021, and 2025 to train installers for the solar projects authorized and contemplated under the Solar for All program and other RPS programs. The job training program is to be “designed to ensure that entities that offer training are located in, and trainees are recruited from, the same communities that the program aims to serve and that the program provides trainees with the opportunity to obtain real-world experience.”⁵⁶⁷

The availability of job training opportunities for Solar for All projects depends, in part, on the availability of graduates of the solar training pipeline program. ComEd’s Request for Proposals from potential training providers was issued August 1, 2017 and remained open until September 30, 2017.⁵⁶⁸ The RFP emphasizes the need for training providers to include trainee recruitment,

⁵⁶⁵ ComEd’s job training implementation plan was approved by the Commission on September 27, 2017 in Docket No. 17-0332.

⁵⁶⁶ 20 ILCS 3855/1-56(b)(2).

⁵⁶⁷ 220 ILCS 5/16-108.12(a)(1).

⁵⁶⁸ See <https://www.cct.org/what-we-offer/request-for-proposals-solar-job-training>.

substantive solar industry training, and post-training opportunities.⁵⁶⁹ Moreover, ComEd has committed “to coordinate with the Illinois Power Agency or its administrator of Illinois Solar for All.”⁵⁷⁰

The second relevant provision is that, for the Low-income Distributed Generation sub-program, “[c]ompanies participating in this program that install solar panels shall commit to hiring job trainees for a portion of their low-income installations” and further that, “an administrator shall facilitate partnering the companies that install solar panels with entities that provide solar panel installation job training.”⁵⁷¹

The Act does not specify what is meant by “a portion” and also does not define who would qualify as a “job trainee” in contrast with the prior provision that specifically ties it to the solar training pipeline program. The Agency notes that Section 16-108.12 of the Public Utilities Act not only creates the solar training pipeline program described above but also creates a “craft apprenticeship program” and a set of six “multi-cultural jobs programs.” The Agency infers that graduates of those programs could reasonably be considered “job trainees” for the purposes of the Low-income Distributed Generation Incentive sub-program within Illinois Solar for All.

ComEd stated in the ICC proceeding reviewing its Section 16-108.12 job training plan that it intends to implement the Solar Craft Apprenticeship Program in coordination with the International Brotherhood of Electrical Workers (“IBEW”) Local 134, which will integrate solar training curricula into its existing electrical craft/trade/skill apprenticeship programs at 18 IBEW sites as well as certain community colleges and high schools.⁵⁷² According to the Plan submitted by ComEd in that proceeding, the Solar Craft Apprenticeship Program appears to include training locations located across the entire State, and not just in ComEd’s service territory.⁵⁷³ This program may be essential for ensuring the availability of job trainees across the State. ComEd has released a report detailing the status of its job training programs under Section 16-108.12 annually since 2019.⁵⁷⁴

To ensure that “a portion” of projects use job trainees, Illinois Solar for All Approved Vendors who participate in the Illinois Solar for All program must demonstrate that at least 33% of Low-Income Distributed Generation projects (on a rolling average basis) include the use of one or more job trainees from the solar training pipeline program, the craft apprenticeship program, or the multi-cultural jobs program. Furthermore, each Illinois Solar for All Approved Vendor will have to demonstrate that for its first year of participation, 10% of the hours worked on all projects will be by job trainees, and that amount would increase to 20% in their second year of participation, and 33% in the third year. The timeline for these increasing annual percentage requirements will start with the beginning of construction of the Approved Vendor’s first project contracted under the Program. **For this draft Second Revised Plan, the Agency would appreciate stakeholder feedback on these annual hours requirements. For example, should a standard baseline to measure these**

⁵⁶⁹ Docket No. 17-0332, ComEd Ex. 1.0 (<http://www.icc.illinois.gov/downloads/public/edocket/451215.pdf>) at 8. As described further at the webpages linked below, recipients of Multi-Cultural Jobs Program grants were announced in August 2017: https://www.comed.com/News/Pages/NewsReleases/2017_08_01.aspx and recipients of Solar Training Pipeline Program grants were announced in December 2017: https://www.comed.com/News/Pages/NewsReleases/2017_12_07.aspx.

⁵⁷⁰ Docket No. 17-0332, ComEd/EDF/ELPC/LVEJO Joint Initial Comments at 5.

⁵⁷¹ 20 ILCS 3855/1-56(b)(2)(A).

⁵⁷² ICC Docket No. 17-0332, ComEd Ex. 1.0 at 12.

⁵⁷³ Id. at 13.

⁵⁷⁴ The reports are available at <https://www.icc.illinois.gov/docket/P2017-0332/documents>.

hours against be established (e.g., a set FTE per MW for each project type)? Are there methods for standardizing record-keeping that should be considered?

Illinois Solar for All Approved Vendors are required to document the use of job trainees provide a summary of job trainee work to the Program Administrator. Illinois Solar for All Approved Vendors may also request to use job trainees from other job training programs so long as the Approved Vendor can demonstrate that completion of the job training program would lead to the trainee becoming a “Qualified Person” under the Part 468 Rule related to the certification of installers of photovoltaic systems (see Section 2.3.2.4 for additional discussion of these requirements). The Agency will consider requests for waivers of this requirement on a case-by-case basis if an Illinois Solar for All Approved Vendor can demonstrate that, despite diligent efforts at recruitment, job trainees are not available in the area where projects are being installed and this would prevent the project from being completed.

The Illinois Solar for All Program Administrator is coordinating with the entities providing job training to maintain a clearinghouse of information that Illinois Solar for All Approved Vendors can use to identify potential job training program graduates to hire. ComEd administers a FEJA Jobs portal (<https://fejajobs.vouchedin.com/>) where graduates of its job training programs created under Section 16-108.12 of the Public Utilities Act can post their resumes and employers can post opportunities for jobs and specific projects. The Program Administrator has provided training to Approved Vendors on how to access and use this portal, and will continue to work with the organizations receiving statutorily-authorizing funding to provide job training in an ongoing effort aimed at encouraging participation in the FEJA Jobs portal by those programs’ graduates.

The Agency and its Program Administrator(s) do not run the job training programs, and therefore, the Agency has limited ability to ensure the success of those programs in effectively training new workers. Rather, the Agency will seek to ensure that the Illinois Solar for All Program creates employment opportunities for those new workers.

8.11. Additional Requirements for Approved Vendors

Because the Illinois Solar for All Program (other than the Low-income Community Solar Pilot Projects) works similarly to the Adjustable Block Program, direct participants must first be approved as ABP Approved Vendors through the process outlined in Section 6.9. Approved Vendors who seek to submit projects into Illinois Solar for All will additionally have to register with the Illinois Solar for All Program and agree to additional terms and conditions to become an Illinois Solar for All Approved Vendor.⁵⁷⁵ An Approved Vendor that does not achieve this status will not be eligible to submit projects. A list of Illinois Solar for All Approved Vendors is available on both the Adjustable Block Program website and Illinois Solar for All website.

The additional requirements for registering to be an Illinois Solar for All Approved Vendor include:

- Description of plans for community involvement in projects (where applicable)
- Plan for inclusion of job training opportunities

⁵⁷⁵ This includes the option to be an Illinois Solar for All Single Project Approved Vendor similar to the Adjustable Block Program Single Project Approved Vendor option. The minimum project size would be 50 kW.

- For those indicating intention to submit projects that receive the Low-income Distributed Generation incentive sub-program, a commitment to hire job trainees for a portion of the projects as described in Section 8.10
- Coordination with the Program Administrator on income verification
- Agreement to allow the Program Administrator and Agency to review and approve marketing materials geared towards the Illinois Solar for All Program
- Agreement to ensure additional consumer protections as described in Section 8.14
- Demonstration that for low-income distributed generation and community solar projects that participants do not have any up-front payments.

The Agency recognizes the importance of equity and minority-/women-owned business enterprise (“MWBE”) participation in the ILSFA Approved Vendor cohort and will continue to work with the Program Administrator to expand MWBE AV participation, including outreach directly to potential MWBE Approved Vendors, as well as partnering with and outreach to equity-focused industry groups.

The Act provides that “[p]riority shall be given to projects that demonstrate meaningful involvement of low-income community members in designing the initial proposals” and that “[a]cceptable proposals to implement projects must demonstrate the applicant's ability to conduct initial community outreach, education, and recruitment of low-income participants in the community.”⁵⁷⁶ For community solar projects, these requirements apply through the requirement to identify partnerships with community stakeholders. It is less clear how those provisions would apply directly to projects that participate in either the Low-Income Distributed Generation Incentive sub-program or the Incentives for Non-profits and Public Facilities sub-program.

To satisfy these provisions, the registration process for the Illinois Solar for All Program will require Illinois Solar for All Approved Vendors to demonstrate their capacities in this area. An Illinois Solar for All Approved Vendor will do so by satisfying all of the following requirements:

- Providing narrative summary of efforts taken prior to the application to conduct community outreach, education, and recruitment
- Listing community-based organizations the applicant has partnered with, including letters from those organizations to verify the partnerships
- Describing in detail ongoing plans for community outreach, education, and recruitment
- Describing staffing for dedicated outreach, education, and recruitment
- Describing plans for ensuring that tangible economic benefits flow to program participants
- Participating in training offered by the Program Administrator on guidelines for marketing, contracting, and standard disclosures for program participants

Failure to maintain a demonstrated commitment to these requirements may result in an Illinois Solar for All Approved Vendor being removed from participating in the Illinois Solar for All Program.

⁵⁷⁶ 20 ILCS 3855/1-56(b)(2).

8.12. Application Process

8.12.1. Project Submissions and Batches

Except for Low-Income Community Solar Pilot Projects, the process for a project to be submitted to the Illinois Solar for All Program generally mirrors that for the Adjustable Block Program described in Section 6.14. Projects are submitted by Illinois Solar for All Approved Vendors through a similar process as the Adjustable Block Program, but the initial minimum batch size is 50 kW. There is no application fee for Illinois Solar for All projects.

Applications will be submitted through the Illinois Solar for All project application portal and will provide the supplemental information required for those projects for Illinois Solar for All in addition to what would be required for an Adjustable Block Program project. If the supplemental information does not demonstrate that the project qualifies for participation in the Illinois Solar for All Program, the project may still be eligible to participate in the Adjustable Block Program through a separate application (including the payment of an application fee), although any such application would be subject to the availability of block capacity in the Adjustable Block Program. A project may not apply to the Illinois Solar for All Program if it is included in a batch of Adjustable Block Program projects that have been submitted to the Commission for approval (or subsequently approved). If a project applies to both programs, the Solar for All application will have to be withdrawn at the time the Adjustable Block Program sends its approval recommendation to the Commission (and vice versa). Additionally, a project may not apply to two sub-programs of Illinois Solar for All within the same program year.

Like for the Adjustable Block Program, Illinois Solar for All projects will be bundled into one contract or confirmation for each approved batch. The Agency will request Commission approval for contracts that include additional Illinois Solar For All provisions. In this Revised Plan the Agency proposes that those contracts will be executed first with the utilities using the allocation from their Renewable Resources Budgets, and then by the Agency using funds from the Renewable Energy Resources Fund. This change from the order contained in the Initial Plan (which was to execute contracts with the Agency first) is to recognize that with the end of the rollover period for utility collected funds there is more urgency to allocated and spend those funds. For contracts allocated to a utility, the Program Administrator will strive to allocate contracts to each utility for projects in their service territory, and in a manner that will obligate funds at a level consistent with each utility's share of funds committed to Illinois Solar for All.

Like the Adjustable Block Program contract process described in 6.14.6, an Approved Vendor's failure to timely execute a product order will potentially subject that Approved Vendor to discipline, and the constituent projects will be considered removed from the Illinois Solar for All Program. Additionally, as discussed in Section 6.15.1 for the ABP, when an Approved Vendor's collateral is forfeited under its ILSFA REC contract (if the contract is with a utility), that collateral amount will be restored to the utility's Renewable Resources Budget, and if the contract is with the Agency, that collateral amount would be deposited into the Renewable Energy Resources Fund.

The process for posting collateral will mirror that for the Adjustable Block Program described in Sections 6.14.6 and 6.16.1. For a Low-Income Community Solar project that is not yet energized at the time of Commission approval, the contract value (for purposes of calculating the required collateral posting) will be based on an assumption that 100% of the project is subscribed by low-income residential households qualifying as "small subscribers."

For Low-Income Community Solar Pilot Projects, the application process will take place through registering for, then bidding in, the competitive procurement for those projects. Prior to accepting bids for the Low-Income Community Solar Pilot Project competitive procurement process, the Agency and its Illinois Solar for All Program Administrator will work with stakeholders to refine and finalize requirements for bidder participation.⁵⁷⁷ The approval of contracts by the Commission will take the form of the Commission approving the results of the competitive procurement.

8.12.2. Project Selection for Sub-programs with High Demand

Projects for each sub-program (except for Low-Income Community Solar Pilot projects) must initially be submitted within pre-determined project submission windows for each program year. In the case that a sub-program has a large number of applications such that the funding required for all eligible applications received within the submission window exceeds that sub-program's total budget (including RERF funds and utility funds)⁵⁷⁸ for that program year, the Agency will establish a protocol that provides a basis for scoring each individual project based on attributes that align with the goals of this Revised Plan and creates a ranking of projects based on these scores.⁵⁷⁹ The highest scoring projects will be selected for funding first, where possible, ensuring funds prioritize projects that directly meet Plan objectives. One objective of this selection protocol will be to minimize the use of random tie-breaking as a means of selection.

Attributes that will receive higher scores include:

- Location with an Environmental Justice Community,
- Location within a low-income community (as defined above in Section 8.6.3),
- Projects developed by Approved Vendors that are women- or minority-owned businesses,⁵⁸⁰ or
- Preferences for types of subscribers in Low-Income Community Solar projects, as outlined in Section 8.6.2;
- Other attributes that align with Plan priorities.

In addition, scoring will be weighted in such a way that helps to ensure a diversity of project development compared with all projects submitted for a given sub-program. For example, additional weighting might be given for:

- Geographic location,
- Project size, or
- Other such attributes that reflect a diversity of projects.

⁵⁷⁷ See Docket No. 17-0838, Final Order dated April 3, 2018 at 161.

⁵⁷⁸ Note that sub-program budgets are adjusted to account for any funds not committed in the previous program year and rolled over (although utility budgets cannot be rolled over starting with the uncommitted 2020-2021 utility budget), administrative expenses, and grassroots education costs. Furthermore, the Agency may adjust allocations of utility-supplied funding if needed.

⁵⁷⁹ This approach has been utilized for the 2018-2019 and 2019-2020 program years. See: <https://www.illinoisfa.com/app/uploads/2019/05/ILSFA-Project-Selection-Protocol.pdf>. The Agency expects that an update to the protocol will include additional granularity in scoring to minimize the likelihood of tied scores that would require random selection of projects.

⁵⁸⁰ During the proceeding to approve this Revised Plan, the Agency recommended a workshop or public comment process to explore expanding this criterion beyond Approved Vendors to include contractors and subcontractors. The Commission agreed that such a process is appropriate. See Docket No. 19-0995, Final Order dated February 18, 2020 at 105.

The project selection protocol should be executed in a way that ensures the goal of 25% of funds going to Environmental Justice communities is met whenever possible. As discussed in Section 8.15.4 below, the 25% allocation for projects located in Environmental Justice communities within each sub-program will be held open until the end of each program year.

After each program year's initial project submission window, if funds for a given sub-program remain available, project applications will be accepted and reviewed on a first-come/first-served basis for the remainder of the program year. If annually allocated RERF funds in a sub-program remain at the end of the program year, the unused funds will be rolled over to the next program year for that sub-program. Additionally, if funds become available due to the withdrawal of any projects during a program year and after project selection, those funds may be made available to the next eligible project on the waitlist for that program year. The waitlist from each program year will not carry over to the following program year.

If the Part II project approval (e.g., energization verification) results in the final REC contracts value being revised downward, the funds made available from that revision would be made available within the applicable sub-programs for consideration by any projects remaining in the waitlist queue for the current program year. The next eligible project on the general waitlist for that sub-program would be awarded those funds or given an option to resize the project in proportion to the newly available funds in a similar fashion to the last projects selected during the project selection process.

The Agency proposes through this draft Second Revised Plan that the Project Selection Protocol developed for the 2021-2022 program year will be maintained without changes for the 2022-2023 program year to promote stability and certainty for Approved Vendors. Any changes to the protocol for the 2023-2024 program year will be finalized at least six months before the start of the program year. This proposal reflects feedback received during the Agency's July 2021 stakeholder workshop and comment process, through which certain stakeholders expressed preference for additional lead time with visibility into the ILSFA project selection protocols. The Agency welcomes stakeholder feedback on this proposal.

8.13. Customer Eligibility

Customer eligibility for the Illinois Solar for All Program is partly defined in the Act. Further refinements are proposed in this section.

8.13.1. Income Guidelines

The Act states that for the Illinois Solar for All Program, "low-income households' means persons and families whose income does not exceed 80% of area median income, adjusted for family size and revised every 5 years."⁵⁸¹

The Agency proposes to use income eligibility guidelines from HUD. HUD bases its housing assistance programs, such as the Section 8 Housing Choice Voucher program on 80% of area median income, adjusted for family size.⁵⁸²

⁵⁸¹ 20 ILCS 3855/1-56(b).

⁵⁸² HUD, FY 2017 Income Limits Documentation System at <https://www.huduser.gov/portal/datasets/il.html>.

Because the Act does not define “area,” the Agency is proposing to use HUD’s definition of an area as a Metropolitan Statistical Area (MSA), a Fair Market Rate (FMR) Area, or a county not in an MSA or FMR. There are 20 MSAs and FMRs, and 62 other counties in Illinois.

Eligibility levels for Illinois Solar For All, based on 2017 HUD guidelines for every area and adjusted for family size, are presented in Appendix F. These guidelines will be updated in 2022.

For Fiscal Year 2017, the HUD eligibility income limits for Illinois as a whole are shown in the table below. For example, a family of four would be considered “low-income” if their household income were less than \$59,300. (Actual eligibility depends on income for an area, rather than for the state as a whole.) HUD has other programs that use “very low” and “extremely low” income measures, at 50% and 30% of AMI that are provided here for reference.⁵⁸³

Table 8-8: HUD Income Limits

HUD State Income Limits: Illinois FY 2017								
Median family income (MFI) = \$74,100								
Persons in household	1	2	3	4	5	6	7	8
30% of median (“extremely low income”)	\$15,550	\$17,800	\$20,000	\$22,250	\$24,000	\$25,800	\$27,550	\$29,350
50% of median (“very low income”)	\$25,950	\$29,650	\$33,350	\$37,050	\$40,000	\$43,000	\$45,950	\$48,900
80% of median (“low income”)	\$41,500	\$47,400	\$53,350	\$59,300	\$64,000	\$68,750	\$73,500	\$78,250

It should be noted that other low-income energy programs, such as the Illinois Home Weatherization Assistance Program (“IHWAP”) and the Low Income Home Energy Assistance Program (“LIHEAP”) have eligibility guidelines that are updated each program year, based on the federal poverty level (not area income), with statewide values. Eligibility guidelines are set for households with income below 200% of the previous year’s federal poverty level, depending on the program. Illinois eligibility guidelines are set by the Department of Commerce and Economic Opportunity and are shown in Table 8-9.⁵⁸⁴

⁵⁸³ <https://www.huduser.gov/portal/datasets/il/il17/State-Incomelimits-Report-FY17.pdf>. For metropolitan area and county level income limits, see: https://www.hudexchange.info/resource/reportmanagement/published/HOME_IncomeLmts_State_IL_2017.pdf.

⁵⁸⁴ Illinois Department of Commerce and Economic Opportunity, “Community Assistance, Energy Efficiency and Infrastructure,” <https://www2.illinois.gov/dceo/CommunityServices/Pages/default.aspx>, .

Table 8-9: Eligibility Guidelines for LIHEAP and WAP in Illinois

2021 Illinois LIHEAP and IHWAP eligibility		
Household Size	30 Day Income	Annual income (200% of FPL)
1	\$2,147	\$25,760
2	\$2,903	\$34,840
3	\$3,660	\$43,920
4	\$4,417	\$53,300
5	\$5,173	\$62,080
6	\$5,930	\$71,160
7	\$6,590	\$79,081
8	\$6,737	\$80,838

Although many households who qualify for LIHEAP and IHWAP will meet the 80% AMI eligibility guidelines of ILSFA, there are certain household sizes in particular counties where 200% of FPL exceeds the local 80% AMI. The Program Administrator will still accept proof of LIHEAP or IHWAP approval as documentation of income eligibility, but with additional verification with DCEO to confirm household income eligibility to reduce inconvenience to the customer or the Approved Vendor. The tables in Appendix F compare HUD eligibility levels to LIHEAP and IHWAP income eligibility levels.

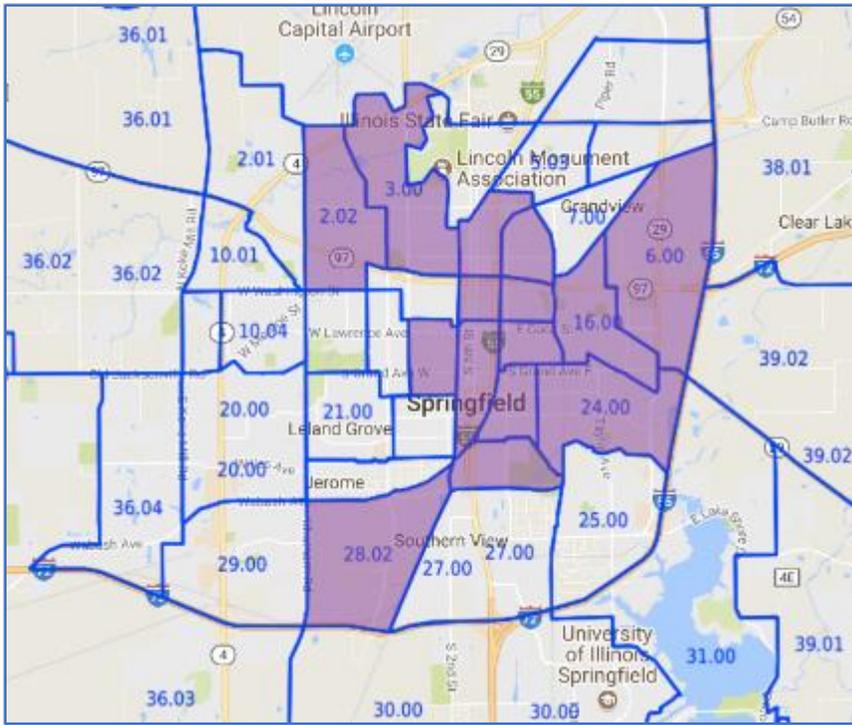
Another approach to identifying low-income customers, by geographic area rather than by individual household income, is to use HUD's "Qualified Census Tracts," which are used to define eligibility for the Low-Income Housing Tax Credit (LIHTC).⁵⁸⁵ Qualified Census Tracts must have 50 percent of households with incomes below 60 percent of the Area Median Gross Income (AMGI) or have a poverty rate of 25 percent or more.

HUD has identified and mapped Qualified Census Tracts ("QCT") nationwide. Overall, there are 657 QCTs in metropolitan areas in Illinois and 49 in non-metropolitan areas (out of 3,123 total census tracts in Illinois). Cook County has the largest portion with 441. Springfield, which has 15 QCTs, is shown in Figure 8-1 as an example.

The Agency will use QCTs (along with subscriber affidavits) as a streamlined method for determining eligibility for low-income community solar subscribers, as discussed in the next section.

⁵⁸⁵ HUD, "Qualified Census Tracts and Difficult Development Areas." <https://www.huduser.gov/portal/datasets/qct.html>.

Figure 8-1: Springfield Qualified Census Tracts



Source: HUD, https://www.huduser.gov/portal/sadda/sadda_qct.html

8.13.2. Determining Income Eligibility

The Agency proposes several approaches to determining income eligibility for the Illinois Solar for All Program.

For projects that participate in the Low-income Distributed Generation Incentive Program sub-program, verification of income should be done at the household resident level. This can be done in several ways.⁵⁸⁶

For buildings with between one and four units, household income can be verified by one of the following means:

- Review of the most recent federal income tax returns
- Income verification through a third-party income verification system
- Verification of participation in another low-income energy program (such as LIHEAP or state-funded IHWAP), in HUD's housing assistance programs where the income eligibility standard is lower than 80% of AMI for that participant, or in other benefits programs where the income eligibility is lower than 80% of AMI.

⁵⁸⁶ In response to arguments raised in approving the First Revised Plan, the Commission determined that the Agency and the Program Administrator shall explore implementing a process to connect interested income-qualified customers with ILSFA Approved Vendors, and that the Agency must implement any such process in a competitively neutral fashion. (Docket No. 19-0995, Final Order dated February 18, 2020 at 108.)

Additionally, while the Agency generally expects the Approved Vendor to verify a potential low-income community solar subscriber's income through one of the methods described above, the Agency recognizes that some potential subscribers would prefer to have their income verified independently of their community solar subscription. In such cases, the potential subscriber may request income verification directly through the Program Administrator and, if approved, that verification would remain valid for 12 months. The Program Administrator would provide the potential subscriber with a verification letter that could be provided to the Approved Vendor.⁵⁸⁷

The Agency received comments suggesting streamlining of the income verification process, particularly for potential participants that demonstrate household-level third-party qualification such as LIHEAP or IHWAP. Establishing income eligibility is a fundamental part of Illinois Solar for All. The Agency does acknowledge that improving processes and overall participant experience will be beneficial, and will work with the Program Administrator and stakeholders to identify ways to simplify the income verification process.

For two- to four-unit buildings, at least two of the households in the building must qualify. For a multi-family building (five or more units), either at least 50% of the households must qualify, or the building owner may demonstrate that the building meets the definition of "affordable housing" contained in the Illinois Affordable Housing Act, namely:

*"Affordable housing" means residential housing that, so long as the same is occupied by low-income households or very low-income households, requires payment of monthly housing costs, including utilities other than telephone, of no more than 30% of the maximum allowable income as stated for such households as defined in this Section.*⁵⁸⁸

In addition, participation in energy efficiency programs that also have an income eligibility requirement that is equal to or less than 80% of AMI may also be considered a means of qualifying a multi-family building.

For residential buildings of two or more units, the building owner will be required to agree to maintain at least half the units as affordable housing for a period of ten years.

For low-income community solar projects, the Agency recognizes that transaction costs of proving income eligibility compared to the value of the incentive may be higher than for an installation of a project on-site, and therefore proposes a streamlined income verification approach:

- A subscriber can be verified as low-income via the same provisions used for the Low-Income Distributed Generation Incentive sub-program.
- A subscriber can be verified as low-income if that subscriber resides in a HUD Qualified Census Tract and provides a signed affidavit that they meet the income qualification level.⁵⁸⁹
- For master-metered five-unit and larger residential buildings, either at least 50% of the tenants must be verified as low-income, or the building must be demonstrated to meet the definition of "affordable housing" contained in the Illinois Affordable Housing Act.³⁷ In

⁵⁸⁷ See Docket No. 19-0995, Final Order dated February 18, 2020 at 108.

⁵⁸⁸ See 310 ILCS 65/3(e). Note that the definition of low-income household contained in that Act mirrors the definition used for Illinois Solar for All, and that very low-income households have an income standard that is even lower.

⁵⁸⁹ The Agency will monitor the use of this provision and may consider modifying the consideration of eligible census tracts (for example to census tracts where at least 50% of households are below 80% of AMI) if the proposed use of the QCT approach appears to be a barrier to facilitating subscription verification.

addition to projects being eligible based on household income, subscriptions for homes or buildings that qualify for US Department of Housing and Urban Development (“HUD”) Project-Based Vouchers or Project-Based Rental Assistance (which are programs for housing units dedicated to low-income tenants) also qualify. The income qualification levels required for participation in these programs is lower than income requirements for the Illinois Solar for All program.

It is the responsibility of the Illinois Solar for All Approved Vendor to track subscribers and document income eligibility for community solar projects.⁵⁹⁰ Approved Vendors will be required to report to the Agency on subscription rates once a year. Illinois Solar for All Approved Vendors will not be required to verify that existing subscribers continue to meet the low-income eligibility requirements, but new subscribers over time will be required to meet those requirements.

8.14. Consumer Protections

The Agency believes that the Plan features a strong set of consumer protections as part of the Adjustable Block Program for both distributed generation and for community solar (see Sections 6.13 and 7.6.2). These protections will also apply to the Illinois Solar for All Program. But several factors lead the Agency to require additional consumer protections for the Illinois Solar for All Program. Thus, to be an Illinois Solar for All Approved Vendor for the Solar For All program, Illinois Solar for All Approved Vendors must agree to the following additional provisions for low-income customers.

- In order to “ensure tangible economic benefits flow directly to program participants,” Illinois Solar for All Approved Vendors must also verify that for residential program participants there are no up-front payments for distributed generation projects, or up-front subscription fees for community solar projects. Illinois Solar for All Approved Vendors must also provide documentation to both the program participant(s), and to the Program Administrator explaining how the project or community solar subscription will result in a cash-flow positive experience for the participant(s) (including an estimate of the monthly savings) – and specifically, ensuring that the savings accruing to each participant, net of any ongoing participation fees, are at least 50% of the value produced by the solar system through avoided usage or net metering credits.⁵⁹¹
- For distributed generation projects, a site suitability report is required to ensure that projects are being installed on properties that will not need substantial structural, roofing or electrical repairs. If repairs are needed, the Illinois Solar for All Approved Vendor must identify the plan for the repairs and how they will be paid for, ensuring that such costs do not place an unsustainable financial burden on the participant. While the site suitability report does not need to be completed prior to the program participant entering into a contract with the Illinois Solar for All Approved Vendor (or their sub-contracted installer), if the site suitability report indicates that the project is not viable, the contract must contain a no-cost cancellation provision.

⁵⁹⁰ While generally the Agency would expect the Approved Vendor to verify a potential low-income community solar subscriber’s income through one of the methods described in this Revised Plan, the Agency recognizes that some potential subscribers would prefer to have their income verified independently of their community solar subscription. In such cases, a potential subscriber may request income verification directly through the Program Administrator, and if approved, that verification would remain valid for six months. The Program Administrator would provide the potential subscriber with a verification letter that could be provided to the Approved Vendor.

⁵⁹¹ See Docket No. 17-0838, Final Order dated April 3, 2018 at 151.

- **Illinois Solar for All Approved Vendors (or their Designees) are required to provide standard disclosures of all costs to program participants. Under the Initial and First Revised Plans, the Agency required that disclosure forms for Low-Income Distributed Generation projects be presented to customers at least seven calendar days prior to execution of the installation contract, and that customers also had the right to cancel their installation contract within seven calendar days following execution of that contract. For this Second Revised Plan, the Agency proposes to eliminate the requirement to present and sign the disclosure seven calendar days prior to contract execution; instead, program participants may be presented with the disclosure form and installation contract contemporaneously, and that following the explanation of standard disclosures to the customer, those documents may also be executed contemporaneously. To provide an additional consumer protection safeguard, the customer’s right to cancellation will be extended from 7 calendar days to 14 calendar days. For contracts related to subscriptions to Low-Income Community Solar Project Initiative projects or Low-Income Community Solar Pilot Procurement projects, customers shall have the right to cancel the subscription agreement within three calendar days after its consummation.**
- Financing amounts, terms, and conditions must be based on an assessment of the program participant’s ability to repay the debt, as defined by Regulation Z, which is a federal rule that implements aspects of the Truth in Lending Act and the Dodd-Frank Act.⁵⁹²
- For low-income customers, loans should not be secured by the program participant’s home or home equity. While such unsecured loans may entail a higher interest rate, especially for customers with low credit scores or little credit history, they avoid the risk of liens and foreclosures for customers who default on their loans.⁵⁹³
- Contracts for financial products must offer terms that include forbearance. If a program participant can show good cause in a request for forbearance, financiers must offer a) suspension of total payments for up to three months, b) a suspension of interest payments for up to six months, or c) a reduction in interest rates for up to twelve months. Missed revenues may be recovered later in the stage of the contract, but no interest may be applied.
- Contracts may not include prepayment penalties.
- **For this draft Second Revised Plan, the Agency proposes to clarify that lease or PPA agreements that allow for ownership of the system to be fully transferred to the participant prior to the 15 year term of the REC agreement will be allowed only in circumstances where full system warranties and full coverage of operations and maintenance needs are included at no additional cost. In these instances, the first-year**

⁵⁹² See Consumer Financial Protection Bureau, April 10, 2013. *Ability-to-Repay and Qualified Mortgage Rule, Small Entity Compliance Guide*, http://files.consumerfinance.gov/f/201304_cfpb_compliance-guide_atr-qm-rule.pdf. Under the regulation (12 C.F.R. § 1026.43, issued under authority of 15 U.S.C. § 1639c), creditors generally must consider eight underwriting factors: (1) current or reasonably expected income or assets; (2) current employment status; (3) the monthly payment on the covered transaction; (4) the monthly payment on any simultaneous loan; (5) the monthly payment for mortgage-related obligations; (6) current debt obligations, alimony, and child support; (7) the monthly debt-to-income ratio or residual income; and (8) credit history.

⁵⁹³ For example, the Illinois Energy Efficiency Loan Program offers unsecured loans at moderate interest rates through on-bill financing, but this is only available for certain energy efficiency measures. See: <http://programs.dsireusa.org/system/program/detail/5152>.

savings must still meet the minimum requirement and the lifetime savings will be calculated based on a 25-year life of the system.

- Marketing and contractual materials must be in the language requested by the customer.
- Contracts must allow a grace period of at least seven calendar days after the customer payment due date before late fees are charged.
- All Illinois Solar for All contracts must include full system warranty, as well as operations and maintenance guarantees for the duration of the REC Contract or 15 years, at no additional cost to participants.

8.15. Environmental Justice Communities

The Act directs the Agency to define and provide special consideration to Environmental Justice Communities in implementing the Illinois Solar For All program. The Act sets as a goal that at least 25% of funds for the Low-Income Distributed Generation Incentive, the incentives for non-profit and public facilities, and Low-Income Community Solar projects sub-programs “be allocated to projects located in environmental justice communities.”⁵⁹⁴ (The provision does not apply to the Low-Income Community Solar Pilot Projects, which are competitively bid.)

The following sections include definitions of terms, a methodology for determining which Illinois communities should be considered Environmental Justice Communities, and how the Agency determined to implement the relevant provisions of the Act. In developing the Illinois Solar for All program participation requirements, the Agency committed to consulting with stakeholders and relevant state agencies, including the Illinois Commission on Environmental Justice and the Illinois Environmental Protection Agency (“IEPA”), to establish specific values and designate specific communities as Environmental Justice Communities; the results of that process are outlined within this section.

8.15.1. Definitions

The Act states that “the Agency shall define ‘environmental justice community’ as part of long-term renewable resources procurement plan development, to ensure, to the extent practicable, compatibility with other agencies’ definitions and may, for guidance, look to the definitions used by federal, state, or local governments.” The term “environmental justice” is not defined in the Act or in other Illinois statutes, but it is helpful to define “environmental justice” in order to define “environmental justice communities.”

The Environmental Justice Act, the 1997 legislation that created the Illinois Commission on Environmental Justice (415 ILCS 155), found that:

- (i) the principle of environmental justice requires that no segment of the population, regardless of race, national origin, age, or income, should bear disproportionately high or adverse effects of environmental pollution;*
- (ii) certain communities in the State may suffer disproportionately from environmental hazards related to facilities with permits approved by the State; and*

⁵⁹⁴ 20 ILCS 3855/1-56(b)(2)(A), (B), (C).

(iii) these environmental hazards can cause long-term health effects.⁵⁹⁵

The Illinois EPA defines the term "environmental justice " as follows:

*"Environmental Justice" is based on the principle that all people should be protected from environmental pollution and have the right to a clean and healthy environment. Environmental justice is the protection of the health of the people of Illinois and its environment, equity in the administration of the State's environmental programs, and the provision of adequate opportunities for meaningful involvement of all people with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.*⁵⁹⁶

The Illinois EPA has also defined a "potential environmental justice community" based on demographic factors, but not environmental factors:

*A "potential" EJ community is a community with a low-income and/or minority population greater than twice the statewide average. In addition, a community may be considered a potential EJ community if the low-income and/or minority population is less than twice the statewide average but greater than the statewide average and that has identified itself as an EJ community. If the low-income and/or minority population percentage is equal to or less than the statewide average, the community should not be considered a potential EJ community.*⁵⁹⁷

The United States Environmental Protection Agency defines an "overburdened community" under both social and environmental terms as:

*Minority, low-income, tribal, or indigenous populations or geographic locations in the United States that potentially experience disproportionate environmental harms and risks. This disproportionality can be as a result of greater vulnerability to environmental hazards, lack of opportunity for public participation, or other factors. Increased vulnerability may be attributable to an accumulation of negative or lack of positive environmental, health, economic, or social conditions within these populations or places. The term describes situations where multiple factors, including both environmental and socio-economic stressors, may act cumulatively to affect health and the environment and contribute to persistent environmental health disparities.*⁵⁹⁸

Both the IEPA and US EPA have developed analytical tools based on their definitions of EJ communities. The IEPA's EJ START is a Geographic Information Systems demographic screening tool developed by IEPA staff that identifies regions with high minority population and/or low-income population. IEPA also adds a one-mile buffer around each regulated facility as a simplified way to identify potential local environmental impacts. It draws from the Census Bureau's American Community Survey 5-year estimates (2011-2015) and is updated annually.

⁵⁹⁵ 415 ILCS 155/5.

⁵⁹⁶ Illinois EPA web site, "Environmental Justice Policy," <https://www2.illinois.gov/epa/topics/environmental-justice/Pages/ej-policy.aspx>.

⁵⁹⁷ Id.

⁵⁹⁸ US EPA, "EJ 2020 Glossary," <https://www.epa.gov/environmentaljustice/ej-2020-glossary>.

The US EPA tool is called EJ SCREEN.⁵⁹⁹ It uses standard and nationally-consistent data to identify communities with greater risk of exposure to pollution based on 11 environmental indicators that measure potential exposure, hazard/risk and proximity, including traffic proximity, particulate matter, and proximity to superfund sites. These indicators are combined with demographic data from the Census Bureau, enabling users to identify areas with minority or low- income populations who also face potential pollution issues.

While these tools are useful, they do not holistically address all aspects of environmental justice. For example, EJ SCREEN evaluates individual environmental indicators but does not look at cumulative impacts.

The most rigorous tool for analyzing impacted communities is the California Communities Environmental Health Screening Tool (CalEnviroScreen) from the California Office of Environmental Health Hazard Assessment (OEHHA).⁶⁰⁰ CalEnviroScreen compiles data on 12 indicators of pollution burden and 8 population characteristics collected at the Census tract level. It then weights certain factors to develop a score for each area. High scoring areas are then considered eligible for a number of state policies, including disposition of some of the revenues from the state cap-and-trade program created under Assembly Bill 32.

Table 8-10: Summary of CalEnviroScreen 3.0 Identification Methodology

Pollution Burden	Population Characteristics
<i>Exposures</i>	<i>Sensitive populations</i>
Ozone Concentrations PM2.5 Concentrations Diesel PM Emissions Drinking Water Contaminants Pesticide Use Toxic Releases from Facilities Traffic Density	Asthma Emergency Department Visits Low Birth Weight Infants Cardiovascular disease (emergency department visits for heart attacks)
<i>Environmental effects</i>	<i>Socio-economic indicators*</i>
Cleanup Sites Groundwater Threats Hazardous Waste Impaired Water Bodies Solid Waste Sites and Facilities	Educational Attainment Housing burdened low income households Linguistic Isolation Poverty Unemployment

Source: OEHHA. * California law prohibits the use of race as a factor in CalEnviroScreen.

The CalEnviroScreen approach is an attractive way to consider defining environmental justice communities but the Agency notes that the development of it was a multi-year, multi-million dollar undertaking. Therefore, the Agency will utilize a streamlined approach that takes the concept of

⁵⁹⁹ See: <https://ejscreen.epa.gov/>.

⁶⁰⁰ California Office of Environmental Health Hazard Assessment (“OEHHA”), *California Communities Environmental Health Screening Tool (CalEnviroScreen)*, <https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20>.

CalEnviroScreen and simplifies it for use in Illinois through using readily available data from the U.S EPA's EJ SCREEN tool. CalEnviroScreen does not account for race in its calculations, but by using data from EJ SCREEN, the Agency will be able to do so.

8.15.2. Approach for Defining Environmental Justice Communities

The Agency determined which areas qualify as Environmental Justice Communities by analyzing data from Illinois census block groups⁶⁰¹ for the following environmental indicators, as described by the EJ SCREEN Tool:⁶⁰²

- National-Scale Air Toxics Assessment (NATA) air toxics cancer risk
- NATA respiratory hazard index
- NATA diesel PM
- Particulate matter
- Ozone
- Traffic proximity and volume
- Lead paint indicator
- Proximity to Risk Management Plan sites
- Proximity to Hazardous Waste Treatment, Storage and Disposal Facilities
- Proximity to National Priorities List sites
- Wastewater Dischargers Indicator

The following demographic indicators are also used by EJ SCREEN and were incorporated into the Agency's methodology:⁶⁰³

- Percent Low-Income
- Percent Minority
- Less than high school education
- Linguistic isolation
- Individuals under age 5
- Individuals over age 64

The Agency considered including the following seven indicators that use data not contained in EJ SCREEN. These are not available at the same level of detail as the indicators using data from EJ SCREEN (more typically they have data at the zip code or county level), and would need to be translated to the block group level. Therefore, the Agency determined in the final methodology that these indicators would be too difficult to incorporate to provide meaningful impact on the evaluation criteria. Namely, these include the following demographic indicators for Sensitive Population Characteristics from the Illinois Department of Public Health:

- Asthma Emergency Department Visits
- Low Birth Weight Infants

and the following environmental indicators from the Illinois Environmental Protection Agency:

⁶⁰¹ There are approximately 10,000 census block groups in the state of Illinois.

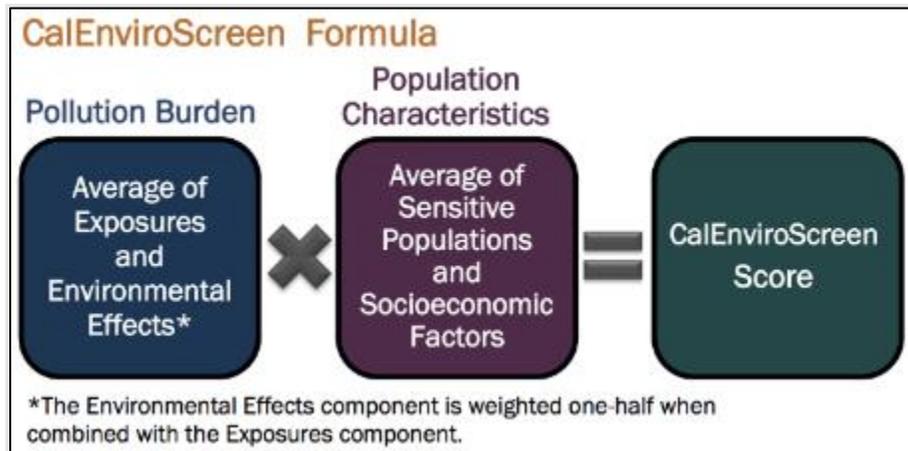
⁶⁰² See <https://www.epa.gov/ejscreen/overview-environmental-indicators-ejscreen>.

⁶⁰³ See <https://www.epa.gov/ejscreen/overview-demographic-indicators-ejscreen>.

- Drinking Water Watch
- Site remediation program
- Leaking Underground Storage Tank Incident Tracking
- State Response Action Program
- Solid Waste Facilities

Using the eleven environmental and six demographic factors listed at the top of this Section 8.15.2, the Agency then weighted each factor using an approach adapted from CalEnviroScreen: census block groups were ranked for each environmental and demographic indicator, a resulting percentile score determined for each census block group within each indicator, and the percentile scores averaged, resulting in an environmental score and a demographic score for each census block group. The two averages were then multiplied together to determine a single Environmental Justice score for each census block group.

Figure 8-2: CalEnviroScreen Formula



Source: OEHHA

Communities with scores in the top 25% of all census block groups statewide are defined as Environmental Justice Communities for the purpose of the Illinois Solar for All Program. This definition will be used to target grassroots education funding and incentives for the Low-income Distributed Generation, Non-profits/Public Facilities, and Low-income Community Solar sub-programs.

A community that is not in the top 25% of scores and thus is not initially defined as being an Environmental Justice Community may request consideration from the Agency to be included. The Agency will consider requests from community-based organizations, local units of government, or community residents for self-designation as an environmental justice community based on a consideration of demonstrated quantitative and qualitative environmental and/or socioeconomic factors that show a disproportionate burden and were not adequately captured in the screening defined above. A request for self-designation must be approved through an Environmental Justice Community Self-Designation Process⁶⁰⁴ prior to any project application being submitted that seeks

⁶⁰⁴ The initial Self-Designation Process developed by the Agency and Program Administrator can be found at <https://www.illinoisfa.com/app/uploads/2019/05/042219EJ-Self-Designation-Process-Final.pdf>. The Agency reserves the right to modify this process in the future based on program experience.

to utilize its location in an approved self-designated Environmental Justice Community as part of its project selection.

The Agency notes that this approach focuses on analysis of census block group-level data, and that communities are typically understood by their residents to be defined through geographic, cultural, and other factors that may, or may not, correspond to census block group boundaries. In addition, the US EPA cautions that data in the EJSCREEN tool is not always reliable at the block group level, and recommends that it may be necessary to aggregate up to larger geographic areas in a “buffer report.”⁶⁰⁵

The Agency will therefore also consider reasonable adjustments to the borders of environmental justice communities from what is calculated through the census block group analysis, provided this does not create an unacceptable analytical burden.

8.15.3. Environmental Justice Community Designations

The Illinois Solar for All Program Administrator undertook the analysis described in Section 8.15.2 in early 2019 prior to the program launch, which included a workshop and an opportunity for written stakeholder comments. The resulting interactive map of Environmental Justice Communities, as well as information from that stakeholder process, is available at www.illinoisfa.com/environmental-justice-communities. The map of environmental justice communities will be updated at least on a semiannual basis to reflect any additional approved requests for self-designation.

8.15.4. Environmental Justice Communities 25% Goal

The Act states that “It is a goal of this program that a minimum of 25% of the incentives for this program be allocated to projects located within environmental justice communities.”⁶⁰⁶

For the Low-Income Distributed Generation Incentive, the Low-Income Community Solar Project Initiative, and the Incentives for Non-profits and Public Facilities sub-programs, the Agency will reserve 25% of each sub-program’s annual budget to support projects in environmental justice communities. If the 25% of funds in each sub-program are fully allocated to projects in environmental justice communities, then subsequent applicant projects in environmental justice communities would still be eligible using the general available budgets. The 25% reservation of funds for environmental justice communities will be held open within a sub-program until filled within a program year, then reset at the beginning of each new program year.

8.16. Program Changes

Several provisions in the Act anticipate the ability to revise program provisions. In addition to the provision described in Section 1-56(b)(4) of the Act that allows stakeholders to propose additional programs, an additional provision allows the Agency to reallocate funds between programs:

“The allocation of funds among subparagraphs (A), (B), or (C) of this paragraph (2) may be changed if the Agency or administrator, through delegated authority, determines incentives in subparagraphs (A), (B), or (C) of this paragraph (2) have not been adequately subscribed to fully utilize the Illinois Power Agency Renewable Energy

⁶⁰⁵ EJSCREEN Technical Documentation, at <https://www.epa.gov/ejscreen/technical-documentation-ejscreen>.

⁶⁰⁶ 20 ILCS 3855/1-56(b)(2).

Resources Fund. The determination shall include input through a stakeholder process.”⁶⁰⁷

With this draft Second Revised Plan, the Agency is not proposing a change in allocation of funds.

For this draft Second Revised Plan the Agency has throughout this Chapter proposed a variety of adjustments to the program pursuant to the following provision:

“Following the Commission’s approval of the Illinois Solar for All Program, the Agency or a party may propose adjustments to the program terms, conditions, and requirements, including the price offered to new systems, to ensure the long-term viability and success of the program. The Commission shall review and approve any modifications to the program through the plan revision process described in Section 16-111.5 of the Public Utilities Act.”⁶⁰⁸

Stakeholders have suggested a more collaborative stakeholder feedback process, rather than issue- or point-in-time specific engagements. The Agency will work with the Program Administrator to create an ongoing stakeholder engagement process to gather feedback on ongoing program performance, changes, and progress. These more general progress sessions will be held at least quarterly.

Further, the Agency and Program Administrator may consider piloting program or process changes on a limited scale to better understand and measure those changes’ effectiveness before making long term changes to the Illinois Solar for All Program. For example, a pilot may involve coordination with third-party energy efficiency program administrator or Community Action Agency to develop a process that would facilitate connecting participants in energy efficiency programs with Approved Vendors or provide initial site suitability screening.

While some stakeholders have suggested separating multi-family housing from the Distributed Generation sub-program (to keep that program for just 1-4 unit buildings) and creating a new sub-program for larger multi-family buildings, at this time the Agency believes that the differing sets of REC prices and program requirements currently contained in the Low-Income Distributed Generation sub-program are sufficient for larger multi-family buildings.

8.17. Evaluation

Section 1-56(b)(6) requires that this Plan include an approach for independent evaluation of the Illinois Solar for All Program:

“At least every 2 years, the Agency shall select an independent evaluator to review and report on the Illinois Solar for All Program and the performance of the third-party program administrator of the Illinois Solar for All Program. The evaluation shall be based on objective criteria developed through a public stakeholder process. The process shall include feedback and participation from Illinois Solar for All Program stakeholders, including participants and organizations in environmental justice and historically underserved communities. The report shall include a summary of the evaluation of the Illinois Solar for All Program based on the stakeholder developed

⁶⁰⁷ 20 ILCS 3855/1-56(b)(2).

⁶⁰⁸ 20 ILCS 3855/1-56(b)(4).

objective criteria. The report shall include the number of projects installed; the total installed capacity in kilowatts; the average cost per kilowatt of installed capacity to the extent reasonably obtainable by the Agency; the number of jobs or job opportunities created; economic, social, and environmental benefits created; and the total administrative costs expended by the Agency and program administrator to implement and evaluate the program.”

In January 2019, the Agency held a workshop and took stakeholder feedback to assist in the development of the scope and process for the evaluation.⁶⁰⁹ The Agency then issued a Request for Qualifications/Request for Proposals to select an independent evaluator to conduct the evaluation.⁶¹⁰ This selection process is expressly exempted from the Illinois Procurement Code.⁶¹¹ On August 7, 2019, the Commission approved the contract for the Agency’s selected evaluator, APPRISE, Inc.

The Act calls for an evaluation “at least every 2 years,” but the Agency notes that Illinois Solar For All did not launch for project applications until May 2019. The Phase I Evaluation Report, released in October 2019, focused on the stakeholder outreach process, development of program materials and guidelines, initial Approved Vendor registration, initial project applications, and the development of Grassroots Education efforts, and was included in Appendix G of the First Revised Plan. Four Phase II Evaluation Reports were completed in 2020 and early 2021, which detail the first two years of ILSFA activities and provide recommendations for program improvement.⁶¹²

Recommendations from the Phase II Final Evaluation Report are summarized below. The Phase II Final Evaluation Report will be included as Appendix G to this Second Revised Plan.⁶¹³ Generally, these recommendations do not require specific changes to the Plan but rather can be considered and potentially implemented through ongoing program administration, and the Program Administrator has or will be implementing many of these recommendations. Where applicable, changes proposed in this draft Second Revised Plan reflect these recommendations.

Recommendations

- Low-Income Distributed Generation Sub-program Project Barriers: Continue to reduce barriers to development of DG projects. This may include exploring where program requirements can be reduced, reducing or removing the waiting period between disclosure and contract execution, and reducing the batch requirement for the first set of projects. Also increase outreach to Approved Vendors to encourage them to develop more standard offers for the list provided to potential participants, and work with the Chicago Porch and Roof Replacement Program and similar programs to target households that may have already had roof repair.

⁶⁰⁹ See: <https://www.illinoissfa.com/announcements/2019/01/written-comments-on-illinois-solar-for-all-third-party-program-evaluation/> and <https://www.illinoissfa.com/announcements/2019/02/public-comments-on-third-party-evaluation/>.

⁶¹⁰ See: <https://www2.illinois.gov/sites/ipa/Documents/IPA%20-%20ILSfA%20-%20Program-Administrator%20-%202018-RFQ-02%20%28Released%2001182018%29.pdf> and <https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/IPA-ABP-Program-Administrator-18-RFP-01-20180312.pdf>.

⁶¹¹ 20 ILCS 3855/1-56(f).

⁶¹² See: <https://www.illinoissfa.com/evaluation/>.

⁶¹³ As this Report was still being finalized as of the date of the release of the draft Second Revised Plan, the Appendix will be published shortly thereafter.

- Utility Screening: Future legislation could be considered that specifies how utilities engage with ILSFA and provides funding to support other aspects of project development.
- Limit Program Changes: Program design changes should focus on refinements that reduce barriers to participation in the Low-Income Distributed Generation sub-program. This will allow the Program Administrator to focus on streamlining project development and implementation processes.
- ILSFA Website: The ILSFA website design can be improved to make it easier to find information and understand the program.
- ILSFA Portal: The portal has been adapted as the program has grown, and there are opportunities to streamline, reduce redundancies and increase user-friendly design elements.
- Green Bank: Develop plans for how a Green Bank can aid Approved Vendors in project financing if enabling legislation is enacted.
- Stakeholder Outreach: Implement proactive outreach to stakeholders beyond current email blasts, and engage Community Action Agencies and other organizations that serve low-income households.
- DG Screening: Develop and implement a process to work collaboratively with the community action agencies that administer LIHEAP and IHWAP.
- Part II Process: Reduce challenges with document and photo uploading, job training document collection, and documentation redundancies.

The Agency plans to begin the process of selecting an Evaluator for the next two-year period starting in the fall of 2021. The Evaluator selection process will include opportunities for stakeholder input in the evaluation design.

8.18. Grassroots Education Funding

The Act also directs the Agency to “allocate up to 5% of the funds available under the Illinois Solar for All Program to community-based groups to assist in grassroots education.”⁶¹⁴ For 2020-2021 and 2021-2022, the Agency interprets the “funds available under the [Program]” to be the annual contribution of approximately \$11.7 million from the Renewable Resources Budget under Section 1-75(c)(1)(O) of the Act, plus \$16.5 million allocated annually from the RERF for the three non-competitive sub-programs, plus \$2.5 million allocated annually from the RERF for the Low-Income Community Solar Pilot Projects.⁶¹⁵ Therefore, the maximum available annual budget for grassroots

⁶¹⁴ 20 ILCS 3855/1-56(b)(3).

⁶¹⁵ While for three of the sub-programs there are defined program year funding levels available, that concept does not apply cleanly to the Low-Income Community Solar Pilot Project sub-program. For simplicity, the Agency is proposing to allocate the total available funding for that sub-program (\$37.5 million) over 15 years, which is the length of time that projects from the sub-program would be delivering RECs to the Solar for All Program.

education is \$1.53 million for these two program years; the Agency reserves the right to allocate less than this amount.

For the purposes of grassroots education, community-based organizations must be registered non-profit entities, excluding trade or political non-profits. It is recognized that the definition of community-based organizations or non-profit is very broad and may include a variety of organization types. It is not required that non-profit organizations have federal 501(c)(3) status, and collaborative or fiscal sponsorship should be encouraged to ensure that very small, hyper-local organizations can participate. Qualified organizations should work within the communities in which they will be providing grassroots education. Grassroots educator entities will be chosen through competitive RFPs issued periodically and selected grassroots educators will be subcontractors of the ILSFA Program Administrator. Pursuant to the Initial Plan, the first selection of grassroots educators was made in June 2019.⁶¹⁶

As noted in Section 8.8, grassroots education funding will be prioritized towards Environmental Justice Communities to help meet this goal. Up to 60% of the funding (or 3 percentage points of the 5%) will be used for this purpose. Grassroots education topics could include solar basics, program requirements, consumer protection, program benefits and opportunities, job training opportunities, environmental justice community issues, or community engagement, among many others. One objective of the grassroots education strategy will be to ensure that campaigns collectively reach a diversity of households and communities, topics, and geographies over time.

Non-profit organizations providing grassroots education to communities must ensure that outreach and education provided does not serve the interest of any Approved Vendor or other solar developer above any other. When grassroots education events are open to Approved Vendors, all Approved Vendors should have an equal opportunity to participate in a transparent manner. No organization providing grassroots education services should have a current financial relationship with an ILSFA Approved Vendor where the grassroots education organization receives payment for such services, and any past relationships should be clearly disclosed when submitting proposals. Community-based organizations may work with Approved Vendors in the capacity of developing a solar project for their own property. Community-based organizations receiving grassroots education funding are also permitted to provide referrals to Approved Vendors who request assistance in identifying either community organizations or property owners that are interested in seeing community solar projects developed in their communities, provided there are no financial payments or other benefits received by the grassroots education funding recipient in exchange for such referrals.

⁶¹⁶ See: <https://www.illinoisfa.com/announcements/2019/06/announcing-grassroots-organizations>.